OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **February 7, 2020**

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FROM:	David Schutz, P.E., New Source Permit Section
SUBJECT:	Evaluation of Permit Application No. **2017-1908-C (M-2)(PSD)** HollyFrontier Tulsa Refining LLC (Formerly Holly Refining & Marketing) Expansion of Tulsa Refinery (SIC 2911) East Refinery (FAC ID 1458) 902 W. 25th Street, Tulsa, Tulsa County (36.126°N, 96.002°W) Portions of Sections 13, 14 and 23, T19N, R12E

I. INTRODUCTION

HollyFrontier Tulsa Refining (HFTR) has requested a modification to their Prevention of Significant Deterioration (PSD) construction permit, Permit No. 2012-1062-C (M-13)(PSD) issued March 21, 2019. This application adds various projects on the Fluid Catalytic Cracking Unit (FCCU) which increase its capacity, updates the emissions from the FCCU, reflects the replacement of the FCCU regenerator and FCCU Charge Heater B-2, the replacement of the FCCU cooling tower (an end-of-life replacement with a unit of identical capacity), and other ancillary projects associated with the FCCU process unit. A new Residual Oil Supercritical Extraction (ROSE) unit permitted for construction is being removed from the permit, along with its 42-MMBTUH helper heater. Project netting and the ambient impacts analyses are being updated. The FCCU Charge Heater B-2 will be incorporated into the BACT analysis for heaters between 100 and 250-MMBTUH for CO, PM_{10}, and $PM_{2.5}$. An additional BACT analysis for the FCCU Regenerator is being added to the permit evaluation. The proposed changes to the PSD permit for the East Refinery are evaluated in the following updated PSD analysis.

The FCCU Charge Heater B-2 (165-MMBTUH) is being moved from EUG-9 to EUG-26 since it is becoming subject to New Source Performance Standards (NSPS) Subpart Ja based on replacing a 150-MMBTUH heater with a 165-MMBTUH heater. The FCCU cooling tower will remain in EUG-19; emissions of the replacement unit are identical to the existing tower. The FCCU Regenerator will remain in EUG-11, but will be revised from being subject to NSPS Subpart J to NSPS Subpart Ja and its hourly and annual emissions will be increased.

HFTR and Holly Energy Partners (HEP) operate the Tulsa Refinery and product loading terminal under three separate permits. The two refineries owned by HFTR were acquired at separate times; therefore, they are permitted separately. The loading terminal is owned and operated by HEP, resulting in another separate permit for it. However, the two refineries and loading terminal are interconnected and collocated, requiring that they be treated as a single facility when conducting a PSD analysis. For the purpose of the PSD analysis only, HFTR and HEP together are at times referred to as "Holly."

In 2014, HFTR and HEP proposed a construction project to expand the refineries and loading terminals. The project commenced in the 2015 time frame. There will be new process units added and modification of existing process units such that the total capacities of the refineries will be increased to 170,000 barrels per day (BPD) from 160,000 BPD. There will be "associated" emissions increases from most units in the refinery, excepting those emissions units which are independent of unit process rates such as emergency engines, fugitive VOC leakage from valves, flanges, etc. The net emissions change analysis applies to all three, and all PSD analyses other than BACT will encompass all three facilities. The BACT analysis in this permit will be limited to the types of units being added to the East Refinery.

HFTR has also obtained a modified PSD construction permit for the West Refinery (Permit No. 2010-599-C (M-8)(PSD)). That permit includes the following items:

- The MEK Unit itself has fugitive VOC leakage components in EUG-7. The fugitive component counts are being updated from the previous permit. The "MEK Unit" uses methyl ethyl ketone to extract wax from paraffins from the Lube Extraction Unit (LEU). Since the unit was considered "modified" previously, making it subject to NSPS Subpart GGGa, the counts update is not a "modification" in the context of NSPS, but does change emission rates.

- The external shell of the Crude Distillation Unit (CDU) will be repaired. The permit application is treating this repair project as a "life extension" project subject to PSD permitting analyses. The primary effect of this change is moving the fugitive components from EUG-7 to EUG-8; all other changes in throughputs and emissions are part of the overall project to expand the refineries.

- The HFTR-West Refinery Asphalt Truck Loading Dock has four bays. Since about 1992, only one bay has been needed; the other three have been out of service. One of the out of service bays has been reactivated and an additional loading bay was installed in August 2016. The re-activated and new bays allow East Refinery Vacuum Tower Bottoms (VTB) and Propane Deasphalter (PDA) to be sent to the Coker. The resulting emissions have been added to EUG 32 (0.05 TPY).

The overall project is subject to PSD review for added emissions of greenhouse gases (GHG), carbon monoxide (CO), nitrogen oxides (NO_X), and particulate matter (PM_{10} / $PM_{2.5}$). Full PSD review consists of:

A. determination of best available control technology (BACT)
B. evaluation of existing air quality and determination of monitoring requirements
C. evaluation of PSD increment consumption
D. analysis of compliance with National Ambient Air Quality Standards (NAAQS)
E. ambient air monitoring
F. evaluation of source-related impacts on growth, soils, vegetation, visibility
G. evaluation of Class I area impacts.

The refinery will accept NSPS Subpart Ja limits on SO_2 emissions on all fuel gas combustion devices to net out from PSD for SO_2. The Projected Actual Emissions from selected, existing fuel gas combustion devices were based on 25 ppm H_2S in refinery fuel gas. Reductions required for netting have been added to the East Refinery construction permit.

II. FACILITY DESCRIPTION

The East Refinery is a fuels refinery with several major process units. Other activities include various minor processes outside the major units, including storage and transfer of products. Much of the equipment was placed in service before the promulgation of permitting requirements. The oldest construction dates from approximately 1907, when the Texas Company commenced building in the area. Sinclair purchased the facility from Texaco in 1983, and then HFTR purchased the refinery in 2009. Refinery property covers approximately 470 acres.

Refining is a complex process to make crude oil into a variety of products, including gasoline, heating oil, lubricants, and feedstocks for other industries. Refining equipment and processes involve a certain amount of iterative treatment, in which materials may be processed more than once at a particular location or may be returned to an earlier step in the system for further handling. Only those processes necessary to understand the basic principles are presented.

A very general description of the entire process at this particular refinery starts with crude oil being processed in the Crude Unit. Process streams flow from the Crude Unit to the Fluid Catalytic Cracking Unit (FCCU), the Distillate Hydrotreating Unit (DHTU), Naphtha Hydrodesulfurization Unit (NHDS), and the Unifiner/Penex (Penex). A residual stream currently becomes asphalt or residual fuel oil; in the near future, that residual stream is planned to be processed for extraction of gas oil and asphaltene feedstocks. Tulsa Refinery primary products are classified as gasoline, distillate, residual fuel oil, and asphalt, but there are also ancillary products, such as propane, butane, propylene, and sulfur.

Note that Emission Unit Groups (EUGs) are based on different criteria from those used to describe process units, so descriptions of the EUGs do not match those of the processing units. For example, EUG #9 consists of heaters found in three different units. Similarly, the storage tanks are divided into EUGs based on roof design and permit status.

A. Crude Distillation Unit (CDU)

Distillation is a thermal process that separates product fractions out of a mix of materials based on differences in boiling points. The CDU separates crude oil into intermediate products, which are either feedstocks for downstream units or residual products. Sour crude, defined by HFTR as crude oil with sulfur content greater than 0.5% by weight, represents approximately 10% of all volume processed by this unit. The remaining 90% sweet crude at the Tulsa refinery has historically averaged approximately 0.4% by weight sulfur.

Crude oil is currently brought to the refinery by pipeline. Sweet and sour crude are segregated in storage tanks and are processed in separate batches through the CDU. All crude is de-salted before entering the distillation towers to remove chlorides that would be damaging to piping and vessels. Sweet crude is usually injected into sour crude runs. There are fugitive emissions from the CDU. The only point source is a common stack serving two heaters. These gas-fired heaters serve the atmospheric distillation tower and the vacuum distillation tower (EUG 9, Point ID 6155). Crude flows through the atmospheric tower first, where the lighter ends are removed or distilled. "Atmospheric" simply refers to the fact that the constituents distilled in the tower are capable of vaporizing at atmospheric pressure. Heavier ends that are not distilled in this tower are then run through the vacuum tower for further separation. A vacuum is achieved in the vacuum tower through use of three stages of steam ejectors. Condensers remove condensable vapors to the greatest extent possible after each of the ejectors. The vent gas flows to the wet gas compressor (J-50) within the FCCU or into the flare system if J-50 is not operating. Some material is refluxed, meaning that it is taken out of the column and reintroduced at an earlier point to achieve better separation into distinct product fractions. Refluxing is also a method for taking heat out of the tower. It is one of the processes that is used at different points and that constitutes one of the techniques to improve performance and more efficiently process materials in the CDU. The project involves modification of the CDU Atmospheric Tower Heater from 200 to 380 MMBTUH capacity which allows throughput to increase from 63,000 BPD to 70,000 BPD. The heater is greatly oversized to ensure it does not create a bottleneck.

HFTR defines eight outputs from the CDU in order of increasing molecular weight as follows. Numbers 1 - 6 come from the atmospheric tower, while 7 and 8 come from the vacuum tower.

1. Light ends. This stream is methane and ethane and goes to the FCCU wet gas scrubber.
2. Butane/propane. This stream goes to the DHTU.
3. Light straight run. This is mostly C_5 material and goes to the Penex.
4. Naphtha. This material goes to the NHDS.
5. Kerosene. This goes to the DHTU.
6. Light atmospheric gas oil. This goes to the DHTU.
7. Gas oils. These go to the FCCU.
8. Vacuum resid. This is the residual material or "bottoms" remaining after all other outputs have been captured. Resid currently goes directly for sale as asphalt or roofing flux. (There are no asphalt blowstills or other oxidation processes utilized at the Tulsa Refinery.)

The facility refers to the sour bottoms as asphalt and to all other material as "flux." Intermediate storage for both materials is in heated tanks.

B. Fluid Catalytic Cracking Unit (FCCU)

The FCCU treats gas oils from the CDU with heat in the presence of a catalyst. Generally, hot gas oil from sweet crudes is mixed with cold gas oil from sour crudes, and the situation is reversed when sour crude is being processed. The FCCU has current capacity estimated at 24,000 BPD with a maximum anticipated processing rate of 28,400 BPD. “Gas oils” are heavier than diesel and lighter than the residual products taken from the CDU. Heavy molecules are broken or “cracked” into lighter molecules that allow the facility to increase the production of liquid fuels. A distillation tower then separates these products into gasoline and diesel components, as well as producing feedstock for the Alkylation (ALKY) and Scanfiner (SCAN) Units.

FCCU catalyst is regenerated continuously to prevent coke build-up, with sufficient catalyst added daily to maintain a relatively constant inventory and level of catalytic activity. Spent catalyst is removed from the regenerator every few days and stored for sale to other refiners or catalyst brokers. This catalyst is valuable and various devices control potential air emissions of it, to minimize its loss. The first set of these devices consists of cyclones in the reaction vessel. In addition, the regenerator contains five three-stage cyclones. The FCCU stack is served by a wet gas scrubber (WGS). Salts and particulates removed by the WGS are shipped offsite for disposal, while the liquid will be sent to the oily wastewater collection system. A selective catalytic reduction (SCR) system has been added to control NO_X emissions. Installation of the SCR required the addition of a 20,000-gallon tank for aqueous ammonia and two 6,400-gallon tanks for sodium hydroxide. The aqueous ammonia is an ammonium hydroxide solution with less than 20% concentration of ammonia. Carbon monoxide emissions from the regenerator are minimized through complete combustion by controlling the excess oxygen content in the flue gas. The FCCU is very difficult to shut down and start up due to the high temperatures involved and the volume of catalyst circulating through it. These activities are managed and tracked through the facility’s startup, shutdown, and malfunction plan (SSMP).

Similar to the handling of crude in the CDU, products of this cracking process are distilled thermally in the tower. Heavy ends, or tower “bottoms,” are known as decanted oil. Light ends from this unit and gasses from the CDU are compressed and run through an absorber at the FCCU. Any remaining gas becomes part of the refinery fuel gas system. A set of electrically-driven compressors is used to compress and circulate the unit gas for further processing. These compressors are often called the “wet gas compressors.”

A gas-fired charge heater (B-2) supplies heat for current operation of the FCCU. Heat to perform the function of this reboiler is now taken from the fractionator slurry bottoms. A gas-fired air heater (B-1) is used only during FCCU startup. A gas-fired steam superheater has been idle since 1996. Heat previously supplied by the superheater is now obtained from B-2.

Propylene loading of railcars (3-spot) and trucks (1-spot) is functionally connected to the FCCU. Additionally, the FCCU is responsible for the operation of two flares, all pressurized spheres, and all pressurized “bullet” tanks except for three tanks located at the ALKY Unit. The CDU, FCCU, ALKY, POLY (polymer), and “Penex” (isomerization, discussed in Item “C” following) Units feed Flare #1. Everything else is directed to Flare #2. During normal refinery operation, both flares feed into a common header and are directed to the flare gas recovery unit.

Part of the expansion project is improvement to the FCCU, replacing the reactor, riser, and feed nozzles with modern designs. Additionally, the refinery will replace the regenerator, the charge heater, and cooling tower, and will conduct other ancillary projects associated with the FCCU process unit.

C. Unifiner/Penex Unit (Penex)

Penex is a process that was installed at the ISOM (Isomerization) Unit in 2002. The ISOM was commissioned in 1987 by modifying a catalytic reforming unit (CRU) that had been idle for a long period. The Penex upgrades the octane of light straight run naphtha from the CDU by isomerizing the normal pentanes to isopentanes. The Penex also saturates benzene, thus reducing the benzene and aromatic levels in gasoline produced by HFTR. Light straight run naphtha from the CDU is sent to intermediate storage before it is charged to the Penex. Penex contains two reactors that can be operated independently. Catalyst in these reactors has an optimal life of seven years and is reclaimed, but not regenerated. The charge is first treated by the Unifiner reactor to remove sulfur and nitrogen. This is a catalytic process that requires hydrogen from the CCR to combine with the elemental sulfur stripped out of various compounds, such as mercaptans. The hydrogen sulfide thus formed can be stripped out of the stream and sent for processing at the Sulfur Recovery Unit (SRU). Unifiner catalyst is long-lived and normally does not require regeneration.

Products from the Penex are normally sent to intermediate storage as gasoline blending components but can also be blended directly into gasoline. Offgas produced is run through an absorption process before being sent to the fuel gas system. The absorber is light cycle oil from the FCCU. Heavier constituents of the offgas are absorbed by the oil and sent to the FCCU fractionator, while the lighter ends are used as fuel gas. The Unifiner section has a charge heater and stack (EUG 9, Point ID 6167). The normal charge rate to the Penex is approximately 12,000 BPD although it has nominal capacity to charge over 14,000 BPD.

D. Continuous Catalytic Reforming Unit (CCR)

The CCR upgrades the octane of heavy straight run naphtha from the CDU (through the Naphtha Hydrodesulfurization (NHDS) Unit) by dehydrogenating the hydrocarbons, resulting in the production of high octane materials such as aromatics. These high octane “blend stocks” are blended directly into gasoline. This stream is one of the most important components of premium grades of gasoline. HFTR’s reforming process is also called “platforming,” because it uses a platinum catalyst in three reactors. The catalyst is fouled quickly by sulfur, so only sweet naphtha feedstock from the NHDS may be used. This process had been performed by the catalytic reforming unit (CRU), which was modified under Permit No. 98-021-C (M-26) to create the CCR. The existing unit was converted into a CCR capable of processing approximately 22,000 BPD of desulfurized naphtha from the NHDS. Three reactors hold approximately 100 tons of catalyst and circulate 1,000 pounds of catalyst through the regenerator per hour. Catalyst flows down through each reactor, dropping from each reactor to the next. As the catalyst exits the bottom of the third reactor, a countercurrent flow of hydrogen purges hydrocarbon back into the third reactor. Nitrogen then carries the catalyst to filter media at the top of the regenerator structure, where fines are removed from the catalyst before it flows to a disengaging hopper.

The "disengaging" term used here means that this is the point at which the catalyst is no longer borne by the nitrogen; it is "disengaged" or separated from the nitrogen transportation medium. Approximately 5-10 pounds of fines are expected to be removed daily and sent for offsite reclamation. The catalyst is cooled to 250-300°F in the disengaging hopper, and is then dropped into the regenerator. The regenerator has three zones, identified as the diluted air zone, the oxychlorination zone, and the drying zone. Approximately 0.07 mol% oxygen is reacted with the catalyst to begin coke burn-off in the diluted air zone. The low oxygen content and the name of the zone are derived from diluting air with nitrogen. The catalyst then drops to the oxychlorination zone, where it is reacted with air and perchloroethylene (perc), which conditions the catalyst by redistributing the metal on the catalyst. Air is blown across the catalyst in the drying zone to remove any remaining moisture. The regenerated catalyst exits the bottom of the regenerator and is moved with hydrogen to the reduction zone above the top of the first reactor. At this point it is further regenerated by contact with additional hydrogen, which combines with excess oxygen to create water vapor. During reactor operation, chloride is injected into the reactor to help maintain catalyst activity. The regenerator tower vents back through the disengaging hopper, allowing the sulfur and chloride in the regenerator vent gas to be absorbed by the catalyst entering the regenerator. This reabsorption process is known as Chlorisorb. Platforming produces hydrogen that is then used by the NHDS, DHTU (Diesel Hydrotreating Unit), SCAN, and Penex units for desulfurization of their feedstocks, although some of the hydrogen is retained or recycled in the reactors to prevent the reaction from cracking the naphtha. The CCR had first operations on December 11, 2007.

There are five heaters associated with this unit. A 155 MMBTUH heater, identified as the #1 Interheater (10H-113), is described in EUG 26. One stack serves the 101 MMBTUH Interheater #2-1, the 25 MMBTUH Interheater #2-2, and the 120 MMBTUH charge heater, and is identified as Point ID 6163 in EUG 27. The 85 MMBTUH stabilizer reboiler heater is identified as Point ID 6162 of EUG 27. The newer 155 MMBTUH heater was installed with low-NO_X burners and the 120 and 85 MMBTUH heaters have been retrofitted with low-NO_X equipment.

Part of the expansion project is installing an additional 25 MMBTUH heater at the CCR Unit.

E. Naphtha Hydrodesulfurizer Unit (NHDS)

The NHDS removes sulfur from the CCR charge (heavy straight run naphtha). The sulfur removal process is catalytic and requires hydrogen, which is supplied by the CCR. The interdependence of this unit and the CCR requires that sufficient sweet material produced by the NHDS be stored to provide for a startup of the CCR. Sulfur is removed in the form of hydrogen sulfide (H_2S). Most of the offgas from this unit is recycled, with excess gas being amine-treated before going to the fuel gas system. Hydrogen is injected in several places and a large part of the unit has two-phase flow. Some of the hydrogen passes through the system and is being continually recovered, compressed, and recycled. The NHDS is normally shut down every three to four years for maintenance, based on catalyst life. The catalyst is not normally regenerated and is replaced every few years. Spent catalyst is sent off site for either regeneration or metals reclamation and disposal. This unit had first operations on March 20, 2006. A pre-modification capacity of 22,000 BPD was stated for this unit.

There are two heaters with low-NO_X burners at this unit. A 39 MMBTUH charge heater and a 44.2 MMBTUH stripper reboiler heater are both described in EUG 25. Part of the expansion is installing an additional 10 MMBTUH heater at the NHDS Unit.

F. Distillate Hydrotreating Unit (DHTU)

The old naphtha/distillate HTU was converted to a DHTU capable of processing approximately 24,000 barrels per day (BPD) in 2006. Conversion included new internals in the reactor, such as reducing the number of catalyst beds, using a new catalyst, and redesigning the quench nozzles. There are several vessels, including a high pressure separator, an amine treater, a coalescer, a salt tower, and various air and water coolers. The existing HTU charge heater remains in service as the DHTU charge heater, but the stripper reboiler heater was permanently removed in 2006. First operations at the DHTU occurred May 25, 2006. The refinery interconnection increased the capacity to 40,000 BPD, and the project will further increase capacity to approximately 45,000 BPD.

The DHTU removes sulfur from diesel blend stocks. Both #1 and #2 diesel streams are treated in the DHTU. Naphtha is treated by the NHDS (see E above). The DHTU normally treats distillate streams from the field or hot from the CDU or the FCCU. Gases from this unit are treated before going to the fuel gas system. The DHTU is normally shut down every three to four years for maintenance, based on catalyst life. The catalyst is not normally regenerated and is replaced every few years. The catalyst is sent off site for either regeneration or metals reclamation and disposal. The DHTU is dependent on the CCR for hydrogen. The DHTU is also responsible for the Light Hydrocarbon Treating Unit (LHC) which treats light hydrocarbon streams to remove hydrogen sulfide.

There are currently two emission points associated with this unit; one active and one inactive. The charge heater stack is Point 6157 in EUG 27. The other stack is Point ID 6156 (was in EUG 9) common for both the splitter and fractionator reboiler heaters, both of which were idled as part of the conversion of the old HTU to the DHTU. Part of the expansion is installing an additional 50 MMBTUH heater at the DHTU Unit.

G. Alkylation Unit (ALKY)

Alkylation is a process that creates large molecules by reacting two shorter molecules in the presence of a catalyst. In this case, the alkylate produced is typically high-octane material necessary for blend stock. Debutanizer net overhead from the FCCU is rich in butenes and serves as ALKY feedstock. The feed is pre-treated by the POLY. Treated feed first passes through a deethanizer. Light ends are sent to the fuel gas system and the feed is sent to the propylene splitter at the POLY unit, as described in Item "H" following. The remaining olefin feed, consisting mostly of butenes, is returned to ALKY to be reacted with isobutanes using sulfuric acid as a catalyst to produce the alkylate. The process uses isobutanes greatly in excess of the stoichiometric amount, so the alkylate is fed through three more towers, those being the depropanizer, deisobutanizer and debutanizer. Historically, approximately 3,500 BPD of alkylate has been produced. The facility accepted a limit of 5,500 BPD to avoid PSD consideration under Permit No. 98-021-C, issued October 18, 2000; that limit is being relaxed to 6,500 BPD. The ALKY receives sulfuric acid and stores it for use. It also sends spent acid for regeneration. Sulfuric acid is loaded from and unloaded to trailers at the ALKY, and can also be received from and loaded into rail cars. ALKY personnel are also responsible for three pressurized bullet tanks, Nos. 58, 59, and 60, located on the unit (EUG 22, Point ID 6288 through 6290). One of these tanks holds butane, a second holds isobutane, and the third is a surge tank used for emergency service. There are no point sources associated with this unit.

H. Poly Pretreat Unit (POLY)

This area of the refinery was originally a polymerization unit, hence the name POLY. Most of the unit has been idle since some time prior to HFTR's purchase of the refinery, but some pieces of equipment have been used for other purposes. Feed for the ALKY unit is treated by the POLY to remove sulfur and any other impurities that might harm the catalyst or otherwise disturb the reaction. An amine system removes hydrogen sulfide, caustic solution removes residual hydrogen sulfide and mercaptan sulfur, and a water wash removes basic nitrogen compounds. A propene recovery system, often referred to as the propylene splitter, was started at the POLY unit in 1996. Approximately 600 BPD of propene have been recovered, stored, and sold as a product in the past. POLY is estimated to have average capacity of 4,000 BPD. There are no point sources associated with this unit.

I. Scanfiner (SCAN)

The SCAN process takes all or a portion of naphtha (often referred to as "cat naphtha" or "cat gasoline") from the fluid catalytic cracking unit (FCCU) and removes the sulfur. The first stage of the process, the diolefin saturator, is designed to convert diolefins into olefins without beginning hydrodesulfurization or olefin saturation. Diolefins need to be removed as they can cause significant fouling in the process equipment.

After diolefin saturation, the cat naphtha is fed into the main SCAN reactor, where hydrodesulfurization, hydrodenitrogenation, and olefin saturation reactions occur over a catalyst. The main product from this reactor is low sulfur cat naphtha, which is a key blend component in producing low sulfur gasoline blends. The process consumes hydrogen and also recovers hydrogen, hydrogen sulfide, and ammonia. The product stream is cooled and water washed prior to entering the reactor effluent separator. Water wash helps prevent chloride build-up in the equipment, and the water is reused to the greatest extent possible through the system. A minimal amount of water is sent to the refinery wastewater system to maintain wash water quality. The hydrogen from the reactor effluent separator, called recycle gas, is sent to an amine absorber in the SCAN unit where the hydrogen sulfide is removed. A small portion of the recycle gas is purged to the fuel gas system to maintain adequate hydrogen purity and makeup hydrogen is fed into the recycle gas upstream of the amine absorber. The recycle gas is then compressed and sent back to the reactor section. Liquid hydrocarbon from the separator is sent to the product stripper, where light ends (butane and higher) and hydrogen sulfide are removed. The non-condensable gas stream (hydrogen, hydrogen sulfide, ammonia) from the separator is sent to an existing amine absorber where it is amine scrubbed for hydrogen sulfide removal prior to injection into the fuel gas system. Low sulfur gasoline from the product stripper is sent to gasoline blending after cooling. ARU (Amine Regeneration Unit) #1 processes the sour amine solution from the amine absorber. Acid gas from the ARU is vented to the sulfur recovery units (SRU#1 and/or SRU#2).

The hydrogen utilized in the SCAN process is obtained from the excess hydrogen produced by other process equipment. This hydrogen would otherwise be blended into the refinery fuel gas system and used to fire the various process heaters and boilers at the refinery. While the SCAN process generates a small quantity of fuel gas, any additional fuel gas demand at the refinery created by removal of the hydrogen from the fuel gas system is satisfied by purchasing natural gas. First operations of the Scanfiner unit occurred December 17, 2004.

J. Sulfur Recovery Units (SRU #1/ SRU #2)

The SRUs recover sulfur from acid gas streams and sour water stripper overhead and store it in elemental form for sale. The refinery currently has an amine system that removes H_2S from various gas and liquid hydrocarbon streams. There are six amine treaters (or “contactors”) that contact the different streams with lean amine, where “lean” means that the amine has a low concentration of H_2S. The lean amine absorbs the H_2S, making it into a “rich,” or high-concentration, stream. The ARU regenerates the amine solution by boiling it, producing lean amine to return to the contactors and hydrogen sulfide to feed the SRU. The SRUs use the Claus process. One third of the H_2S is oxidized to form SO_2 and the SO_2 is reacted with the remaining H_2S in the presence of an alumina catalyst to form elemental sulfur and water vapor. The liquid sulfur is stored in a pit for shipping by rail or truck. The reaction does not achieve total removal of sulfur (manufacturer’s guarantee is 99.5%) so the tail gas is scrubbed by Tail Gas Treating Units (TGTU) to recover most remaining sulfur oxides formed before they are released from the stack (EUG 10, Point ID 6152). The TGTUs incinerate remaining H_2S to SO_2, which is then removed by a following caustic scrubber. Scrubber waste products are routed to the wastewater treatment system. Tail gas concentration of SO_2 is maintained below 250 ppm on a 12-hour rolling average. Continuous Emissions Monitoring Systems (CEMS) on both SRUs demonstrate compliance. SRU #2 had first operation on June 1, 2006.

The Sour Water Stripper (SWS) is also associated with this complex of units. The SWS takes sour water from various units and removes ammonia and H_2S. Modifications to the SWS in 2006 replaced the trays, increased the operating pressure of the stripper, and installed a new feed-to-bottoms heat exchanger. These changes increased the capacity to approximately 190 gpm. Offgas from SWS is sent to SRU #2, because SRU #1 has proven incapable of handling this material without fouling of the catalyst. If SRU #2 is unavailable for some reason, SWS will be placed on fresh water feed or shut down and sour water stored in tanks. Upon return to service of SRU #2, any accumulated sour water will be processed and the offgas sent to SRU #2.

The design capacities of SRU #1 and SRU #2 are each 25 long tons per day (LTPD).

K. Boiler House (BOHO)

The BOHO is responsible for steam production for the refinery. The BOHO is also responsible for the other utility systems such as plant air, instrument air, and nitrogen. There are four existing boilers at the BOHO, each capable of producing over 100,000 pounds per hour of 250 psig steam. These boilers primarily burn sweet plant fuel gas. Although each boiler is also capable of burning liquid fuel, the piping to facilitate liquid fuel burning has been removed. Generally, a different boiler is shut down every six months for maintenance. The Consent Decree (Case No. 2:08-cv-0020-WFD) (CD) required that each boiler have its own stack and that each boiler be subject to NO_X control. Now there are selective catalytic reduction (SCR) systems on all four boilers. Continuous emission monitoring systems (CEMS) have been installed on each stack. These are the only emission points associated with the BOHO.

L. Wastewater Treatment Plant (WWTP)

The Wastewater Treatment System collects and treats wastewater generated in the refinery prior to discharging water to the Arkansas River, including both process generated wastewater and storm water. Both federal and state agencies regulate the effluent going to the river. Federal requirements are under the jurisdiction of the Environmental Protection Agency (EPA) and are covered by the National Pollutant Discharge Elimination System (NPDES). State requirements are under the jurisdiction of the Oklahoma Department of Environmental Quality (ODEQ) and are covered by the Oklahoma State Discharge Permit System (OSDPS). Various federal standards govern wastewater operations, including 40 CFR Part 60 (NSPS) Subpart QQQ (VOC Emissions from Petroleum Refinery Wastewater Systems), 40 CFR Part 61 National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart FF (Benzene Waste Operations NESHAP [BWON]), and 40 CFR Part 63 Subpart CC (Petroleum Refineries).

There are five sewer systems, three of which handle oily (process) wastewater and two of which handle (non-process) storm water. Storm water systems are not subject to NSPS Subpart QQQ. Each of the five systems is described as follows.

- Uncontrolled refinery individual drain system (IDS) and uncontrolled “API” (oil-water separator) tanks.
- IDS and API separator tank(s) controlled by BWON. The IDS and API tank(s) were installed in 2005.
- Refinery slop oil system, in which tankage is designed with BWON-compliant controls.
- A storm water collection system that ties into the first common junction box of the uncontrolled refinery IDS. This system collects storm water from concrete pads and areas within unit limits (on-unit).
- A storm sewer system that collects storm water from outside the process unit battery limits (off-unit) and routes it to the off-unit storm pond. The pond holds approximately 33 million gallons of this water that is normally used for cooling tower makeup water, although it can be discharged to the Arkansas River.

HFTR currently purchases approximately 3 million gallons of additional municipal water daily to make up for process use.

The first four systems are all routed to the WWTP. Water entering the WWTP is tested for various impurities at the diversion box. Material with certain levels of impurities is sent to the off-test tank, from which it is later blended back into the treatment system. The water then passes through either of two API separators, with any skimmed hydrocarbon going to a slop oil tank. Water continues to the equalization basin, where it is stirred and aerated and microbial action begins to digest the hydrocarbons. A bio-disk unit continues the digestion process with more “bugs.” Clarifiers separate the dead microorganisms and any other solids from the water for further processing in a digester. Upgrades to the aeration basin and clarifiers were made in 2001 and 2003. Biological material wasted from this process is used as fertilizer to maintain vegetative cover on the facility’s two closed land treatment units. Remaining water goes to the

Final Pond, where it is tested before discharging to the Arkansas River or being used to irrigate the refinery's two closed land treatment units. A large pond and two tanks are available as storage for rain that falls on the process units. Tank 477 with a nominal capacity of 5,031 bbls was constructed in conjunction with Permit No. 98-021-AD (M-37) and acts a wide spot in the line to slow storm surge flow from the NHDS and SRU#2 units. On-unit storm water from tank 477 travels through an uncontrolled IDS and then through tank 476 to the equalization basin. Storm water can be pumped from the on-unit storm water pond to tank 459 and back again as needed for containment. Various water treating chemicals including hydrogen peroxide are used in treating wastewater. Fugitive emissions from the Wastewater Treatment System are included with Equipment Leaks - Process Units.

M. Miscellaneous Points

Miscellaneous equipment leaks or fugitive emissions occur from all piping components throughout the refinery. These emissions are estimated with AP-42 factors and there are two points associated with fugitive emissions. The Hydrocarbon Recovery System consists of an ongoing effort to recover oil from beneath the refinery. It consists of several wells, separators, and storage tanks or batteries scattered throughout the refinery. This equipment is moved as necessary to maximize the recovery of oil. The hydrocarbon recovery system has small emissions, but cannot qualify as an insignificant activity because it is subject to 40 CFR Part 63 Subpart GGGGG (EUG 18). There are several cooling towers that serve the refinery. The cooling towers are treated using sodium hypochlorite.

A fuel system using light ends from various processes to feed combustion devices is known as the refinery fuel gas system and the rich gas it carries is frequently called RFG. Fugitive emissions from the RFG system are calculated and listed with other fugitives from each unit.

As noted in the introduction, oldest parts of the facility date from 1907. Some of the equipment at the facility was constructed before state or federal air pollution rules and regulations were promulgated, and many of these sources are grandfathered (exempt from permit requirements). DEQ or a predecessor agency has permitted various pieces of equipment. A list of those permits was contained in the memorandum associated with the initial TV permit. Other environmental permits include RCRA Post Closure for the Flare Area Treatment Unit (EPA No. 990750960-PC) and NPDES wastewater discharge (EPA No. OK0001309 / DEQ No. I72001630).

III. PROPOSED PROJECT DESCRIPTIONS

The proposed projects for each facility are listed following. The new and modified units are categorized as combustion units (heaters); process units with fugitive VOC leakage from valves, flanges, etc.; the Fluid Catalytic Cracking Unit (FCCU); the Continuous Catalyst Regenerator serving the Platformer Unit; and storage tanks.

East Refinery

• A new Naphtha Splitter Reboiler Heater (10H-105, 100 MMBTUH) will replace the existing Naphtha Splitter Reboiler Heater (75 MMBTUH).
• A new 10,000 BPD Liquid Petroleum Gas (LPG) Recovery Unit charging 32 MMSCFD gas;
• Expanded Distillate Hydrotreater Unit (DHTU), with a new 50 MMBTUH HHV helper heater;
• Revamped FCCU, increasing process throughput from 24,000 BPCD to capacity of approximately 28,400 BPD;
• Modified Naphtha Hydrodesulfurizer (NHDS) Unit, with a new 10 MMBTUH HHV helper heater;
• Modified Continuous Catalytic Reforming (CCR) Unit, with a new 25 MMBTUH HHV helper heater;
• A new Naphtha Fractionation Column which will require steam from facility boilers;
• Expansion of the Alkylation (ALKY) Unit to 6,500 BPD, using steam from existing boilers for process heat.
• The CDU Atmospheric Tower Heater will be enlarged from 200 MMBTUH capacity to 380 MMBTUH capacity.
• New tanks will be added to the East Refinery, but the final designs are not yet ready. As an interim measure, a limit of 1.24 TPY VOC from the new tanks will be established.
• HFTR will also make changes to the Penex/Unifiner such as upsizing the reactor, catalyst vessel changes and various components to accomplish the increase authorized by the previous PSD permit.
• HFTR would also like to clarify that as part of the upcoming turnaround and as authorized by the PSD expansion project the various units at the refinery will have fin-fans, exchangers and miscellaneous components replaced to achieve the authorized operation levels. These are the replacement of existing components and do not change the fugitive emissions authorized by the permit.
• The emission factors for the CCR Interheater #2-1 and #2-2 have been revised to 0.15 lb NO_X/MMBTU to be consistent with the Permit No. 2012-1062-TVR2 (M-9), issued July 8, 2016.
• The existing FCCU Charge Heater B-2 (150-MMBTUH) will be replaced with a new, larger 165-MMBTU heater.
• Various modifications will be made to the FCCU increasing its capacity, and throughput of its catalyst regenerator.

West Refinery

• Propane Deasphalter (PDA) Unit revamp and modification to become a Residuum Oil Supercritical Extraction (ROSE) Unit, with a new 76 MMBTUH HHV heater; and
• A new 10 MMSCFD Hydrogen (H_2) Plant will be constructed, with a reformer heater sized at 125 MMBTUH. The heater will be fueled with natural gas or refinery fuel gas, which may include Pressure Swing Absorption (PSA) off-gas.
• New tanks will be added to the West Refinery, but the final designs are not yet ready. As an interim measure, a limit of 26.69 TPY VOC from the new tanks will be established.
• Updates to the MEK Unit Fugitive emissions.
• Repairs to the CDU.
• Reactivation of the Asphalt Truck Loading.

HEP (Loading Terminal and Storage)

- A new 90,000 BPCD Inline Gasoline Blender.
- A new Propane Loading Unit will replace the existing Propane Loading Unit.
- Construction of new tanks with VOC emissions up to 22.1 TPY will be authorized, but specifications for the new tanks are not yet known.
- Updates to the MEK Unit Fugitive emissions.
- Repairs to the CDU.
- Reactivation of the Asphalt Truck Loading.

IV. EQUIPMENT

Tank identifiers include a facility-wide "Tank No." and a "Point ID" used in annual emission inventories. Tank capacities are all stated in barrels. Various tanks have been moved from one EUG to another. Since several units have been moved to another permit, there will be gaps in the sequence of EUGs. Most refinery units contain numerous vessels and myriad valves and connectors. Only the emission points are identified in the following descriptions.

The four new heaters are in EUG-29. The modified CCR #1 Interheater (10H-113) will remain in EUG-26; as the only unit in that EUG, applicability will be changed from NSPS Subpart J to NSPS Subpart Ja.

The modified CDU Atmospheric Tower Heater will be moved by itself into EUG-33.

The modified CCR Unit will remain by itself in EUG-6. The FCCU will also remain by itself in EUG-11.

The new LPG Recovery Unit will be in EUG-28. It will be subject to NSPS Subpart GGGa.

The new Naphtha Fractionation Column will be a separate new process unit in EUG-32, subject to NSPS Subpart GGGa.

The modified DHTU and NHDS units will be in EUG-32. Both become subject to NSPS Subpart GGGa upon modification.

The modified Alky units will be in EUG-32. That unit becomes subject to NSPS Subpart GGGa upon modification.

New process drains at the Naphtha Fractionator Column will be in EUG-17 due to overlap provisions of MACT Subpart CC.

The replacement heaters 10H-105 and B-2 will be in EUG-26 with another new heater subject to NSPS Subpart Ja.

EUG 3 MACT CC Group 2 Storage Vessels - Fixed Roof (FR)

These storage vessels are regulated under 40 CFR Part 60, Subpart UU and 40 CFR Part 63 Subpart CC (MACT CC) Group 2 Storage Vessels and are limited to the existing equipment as it is.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
112	6195	2012	30'	110’	50,000
118	6201	1907	30'	96'	37,500
119	6202	1907	30'	96'	37,500
126	6263	1907	30'	96'	37,500

EUG 4 MACT CC Wastewater Tanks

These storage vessels are regulated under 40 CFR 63 Subpart CC (MACT CC) as wastewater management units and are limited to the existing equipment as it is. Due to the overlap provisions of MACT CC, the requirements of 40 CFR Part 61 Subpart FF (BWON), and 40 CFR Part 60 Subpart QQQ (NSPS QQQ), these vessels are required to comply with Subpart FF to meet the applicable standards under MACT CC, BWON, and NSPS QQQ.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
13	6243	1976	40'	116'	75,250
400	17035	1922	30'	24'	2,400
401	17036	1920	20'	25'	1,700

[1] Originally NSPS Kb tanks, converted to wastewater only.

EUG 6 Continuous Catalytic Reforming Unit (CCR)

The CCR is regulated by 40 CFR Part 63 Subpart UUU, and is limited to inorganic Hazardous Air Pollutant (HAP) of 10 ppmvd corrected to 3% oxygen at the regenerator stack. The facility complies with Volatile Organic Hazardous Air Pollutant (VOHAP) standards by venting organic materials to the flare system.

EUG 8 Fired Boilers

Each boiler exhausts approximately maximum 76,000 ACFM at an estimated 300°F from a 72" diameter stack at 60´ above grade. Listed heat capacities are based on boilerplate capacity of 170,000 pounds/hour of 350 psi, 500°F steam. There were no emission limits applied to this EUG under Title V but it was limited to the existing equipment as it is and remained subject to standards affecting existing units such as OAC 252:100-19. The boilers became subject to NSPS Subpart J effective June 30, 2008, and became subject to NO_X emissions limits. HFTR has taken a voluntary limit equal to NSPS Subpart Ja; SO_2 emissions will be subject to the limit. Each boiler is fitted with SCR for control of NO_X and compliance is monitored by CEMS.

ID	Point ID	Name/Model	Heat Capacity	Construction Date
1	6150	Babcock & Wilcox FH 26	233 MMBTUH	1950
2	6150	Babcock & Wilcox FH 26	233 MMBTUH	1950
3	6151	Babcock & Wilcox FH 26	233 MMBTUH	1950
4	6151	Babcock & Wilcox FH 26	233 MMBTUH	1955

EUG 9 Fuel-Burning Equipment

Various process heaters share stacks. As of June 30, 2008, all fuel gas combustion devices (FGDs) are subject to NSPS Subpart J, effective June 30, 2008. HFTR has taken a voluntary limit equal to NSPS Subpart Ja; SO_2 emissions will be subject to the limit.

The following table shows available information for all heaters.

Source	Point ID	MMBTUH (HHV)	Heater Date
Vacuum Tower Heater	6155	100	1949
FCCU Air Heater B-1 *	6159	38.4	1949
Unifiner Charge H-1	6167	42	1955

* vents to FCCU regenerator stack.

EUG 10 Sulfur Recovery Units

SRU #1 was constructed in 1972 and SRU #2 became operational in June 2006. Each unit has a tail gas treating unit (TGTU) to scrub its exhaust. The TGTU #1 incinerator is rated at 5.6 MMBTUH and the TGTU #2 incinerator is rated at 12.1 MMBTUH. Scrubbed tail gas exhausts TGTU #1 at 3,640 ACFM and 443°F through a 2′ diameter stack at 200′ above grade. Scrubbed tail gas exhausts TGTU #2 at 7,400 ACFM at 154°F through a 2.5′ diameter stack at 101′ above grade. SRU/TGTU #1 is Point ID 6152, and SRU/TGTU #2 is Point ID 36200.

EUG 11 FCCU

Catalyst is regenerated in the FCCU regeneration section, where cyclones remove catalyst from the vent gas. Selective catalytic reduction (SCR) then controls NO_X before the exhaust stream reaches a wet gas scrubber (WGS), where SO_2 and further PM removal occurs. The only emission limits applied to this EUG are those imposed by the MACT Subpart UUU or as described in the Specific Conditions. Compliance with SO_2 and NO_X standards are demonstrated by continuous emission monitoring systems (CEMS) that monitor each pollutant and O_2. An alternative monitoring plan (AMP) was approved by EPA on January 31, 2013**.** A copy of the AMP is found in the Specific Conditions. Operation of the regenerator is regulated by MACT Subpart UUU. The ESP is identified as Point ID 6153. The CD established the regenerator as an affected facility under NSPS Subpart J. Compliance dates as stated in the CD and the modified CD depend on the pollutant and on the averaging period. These details are identified in the Specific Conditions. Approximately 60,000 ACFM (wet) at roughly 150°F is exhausted through a 60" diameter stack at 151´ above grade.

EUG 12 Flares

Each flare is steam assisted with three shielded pilots, flame front generators, and electronic igniters. Pilot flame presence is detected with either infrared cameras or thermocouples in the pilots. Throughputs are highly variable and exhaust temperatures are approximately 1,500°F. The current #1 flare tip was designed in 1968 for 65,000 lbs/hr of 42 average molecular weight gas. The #2 flare tip was designed for smokeless operation at 120,000 lbs/hr of 87 average molecular weight gas and 42,000 lbs/hr of steam, and has a maximum capacity of 352,600 lbs/hr of 67.8 average molecular weight gas. Both flare tips have a diameter of 5′. The June 30, 2008 CD required compliance with the H_2S standard of NSPS Subpart J by December 31, 2009. It also established the flares as affected facilities under NSPS Subpart J. Both flares became subject to the standards of NSPS Subpart Ja on November 11, 2015. Sources in other EUGs under various regulations utilize the flares as air pollution control devices. As noted in the discussion of the FCCU (Section II B), flare #1 handles the CDU, FCCU, ALKY, POLY, and Penex units, and flare #2 handles everything else. During normal refinery operations, both flares are joined to a common header and routed to the flare gas recovery unit. The flares are identified as Point ID 6154.

Flare	Make/Model	Height (ft)	Date
#1	Zink/STF-SA-18	230	1949
#2	Zink/STF-SA-36-C	250	1972

EUG 13 MACT EEEE Tanks

This EUG contains vessels subject to 40 CFR Part 63 Subpart EEEE. Because these perchloroethylene tanks are smaller than 5,000 gallons, these emission sources do not require control, per §63.2343(a).

Tank No.	Year Built	Height	Diameter	Nominal Capacity
10F-163 (CCR)	2007	4'	8'	18 bbl
4V-31 (Unifiner)	2002	13.5'	4.5'	30 bbl

EUG 15 High Vapor Pressure Loading Operations

There are several loading racks that handle VOC materials. The propylene and butane truck loading facilities are on vapor balance systems. The butane rack is “grandfathered” (constructed prior to any applicable rule). There are no emission limits applied to this EUG under Title V, but it is limited to the existing equipment as it is.

Rack	Point ID	Material	Capacity	Date
Butane truck	6171	Butane loading and unloading	4 trucks	1923
Propylene	13404	Propylene loading	2 cars, 2 trucks	Railcars/1996, Trucks/1997

EUG 16 Fugitive Emissions

Equipment leak emissions from components throughout the existing refinery, but not including the proposed new process units (Naphtha Fractionation and LPG), or modified units (DHTU, NHDS, and ALKY) including, but not limited, to the process units and storage tanks are included in this EUG. There are no emission limits applied to this EUG under Title V, but it is limited to the existing equipment as it is. VOC concentrations in ppm are limited by various rules and regulations, including MACT Subpart CC and OAC 252:100-39-15. Aggregated emission points are identified as Point ID 6172.

EUG 17 Wastewater System

The wastewater system consists of several different sewer systems and the wastewater treatment plant, as described in Part N of Section II (Facility Description) above. The facility is subject to 40 CFR Part 61 Subpart FF (BWON) and 40 CFR Part 63 Subpart CC (MACT CC), while areas of the refinery are subject to 40 CFR Part 60 Subpart QQQ (NSPS QQQ). Due to the overlap regulations under MACT CC (40 CFR §63.640(o)), all Group 1 wastewater streams also regulated under NSPS QQQ must meet only MACT CC standards, while all Group 1 wastewater streams also regulated under BWON must meet only BWON standards. A June 11, 2007, EPA Applicability Determination (AD) issued to BP Products North America and signed by George Czerniak, states that a Group 2 wastewater stream may be treated under BWON exclusively if the facility declares it to be Group 1 and satisfies the requirements of Subpart FF for the stream. Given this AD, the entire SCAN Unit, entire NHDS Unit, and new construction at the DHTU and CCR are subject to BWON. The entire SRU/TGTU #2 is subject to NSPS Subpart QQQ. Aggregated emission points are identified as Point ID 13409.

The new Naphtha Fractionation Column will have new process drains constructed, drains which will be subject to NSPS Subpart QQQ and NESHAP Subpart CC. By the overlap provisions of Subpart CC, the new wastewater equipment is required to comply only with Subpart CC.

EUG 18 Hydrocarbon Recovery System

This system was installed in 1982 to recover oil and any other hydrocarbons that may be below the surface of the ground within the refinery. Several wells and tank batteries are involved. Any water recovered is sent to the Wastewater Treatment System and all oil is processed in the refinery. This EUG has no emission limitation. New tanks were installed in 2007, 2008, and 2009. The collection of all points is identified as Point ID 14487.

Tank No.	Height (feet)	Diameter (feet)	Nominal Capacity
B1	6	3.8	12 bbl
B2	6	3.8	12 bbl
B4	6	3.8	12 bbl
B5	N/A	N/A	55 gallons
B7	6	3.8	12 bbl
B8	6	3.8	12 bbl
B9	6	3.8	12 bbl
B10	6	3.8	12 bbl
B11	6	3.8	12 bbl
B12	6	3.8	12 bbl

EUG 19 Cooling Towers

Number	Point ID	Purpose	Date
3	25053	Cooling water for the FCCU	2019-2020
3a	25054	Cooling water for SCAN	2003
4 and 5	25055	Cooling water for the CDU	1949
7	25056	Cooling water for the ALKY, POLY & ISOM	2007*
8	25057	Cooling water for the OIF	1972
7a	25056a	Cooling water for the ALKY, POLY & ISOM	2012

* Replaced tower built in 1949.

EUG 20 NSPS Kb Tanks (EFR) - MACT CC Group 1 Wastewater

These storage vessels are regulated under 40 CFR Part 60, Subpart Kb and is limited to the existing equipment as it is. Due to the overlap provisions of MACT CC, these vessels are required to comply only with Subpart Kb, except as noted in 40 CFR §63.640(n)(8).

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
476	36590	2005	45'	55’	15,000
478	N/A*	2014	59’	102’	100,000
477	N/A	2006	40’	30’	5,000
474	15940	1997	48'	106'	73,000
475	15941	1997	48'	106'	73,000

*Tank 478 is being replaced and a new Point ID number has not yet been assigned.

EUG 21 Pressurized Spheres

These units are “grandfathered” (constructed prior to any applicable rule). There are no emission limits applied to this EUG under Title V but it is limited to the existing equipment as it is. Because there are no measurable emissions from any of these tanks, they are all classified as Insignificant, and listed here only for completeness.

Tank No.	Point ID	Year Built	Diameter (feet)	Nominal Capacity (bbls)
207	6281	1948	48	9,250
208	6282	1924	48	9,250
218	6284	1986	55	13,750
219	6285	1986	55	13,750
220	6286	1953	51	10,800
221	6287	1953	51	10,800

EUG 22 Pressurized Bullet Tanks

Because there are no measurable emissions from these tanks, they are all classified as Insignificant, and listed only for completeness.

Tank No.	Point ID	Year Built	Length (feet)	Diameter (feet)	Nominal Capacity (bbls)
58	6288	1960	66	12	1,300
59	6289	1960	66	12	1,300
60	6290	1960	66	12	1,300
64	6291	1967	84	10	1,300

Tank No.	Point ID	Year Built	Length (feet)	Diameter (feet)	Nominal Capacity (bbls)
65	6292	1967	84	10	1,300
66	6293	1967	84	10	1,300
70	6294	1979	70	11	1,000
71	6295	1979	70	11	1,000
72	6296	1998	78	10	1,000
73	6297	1998	78	10	1,000

EUG 23 MACT CC Group 2 Wastewater Tanks

These tanks are affected facilities under MACT CC, but there are no standards or requirements under Subpart CC. Therefore, the only requirements are those of NESHAP Subpart FF.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
52	22638	1972	36'	40'	7,500
56	36193	1992	16'	25'	1,400
57	36193	1992	16'	25'	1,400
140	23134	1971	16'	36'	2,900
369	23134	1960	23'	12'	480

EUG 24 Tanks Subject to NESHAP FF

The following tank is subject to the benzene waste organic NESHAP, but is too small to be an affected facility under MACT CC.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
67	23134	1992	12'	10'	165

EUG 25 New Fuel-Burning Equipment with Heat Input < 100 MMBTUH (NSPS Subpart J)

This EUG contains new fuel-burning equipment with heat input less than 100 MMBTUH. These sources are all regulated under NSPS J and MACT DDDDD.

Source	Point ID	MMBTUH (HHV)	Heater Date	NOx lb/MMBTU (HHV)
SCAN Charge (12H-101)	23133	25.2	2004	0.07
NHDS Charge (02H-001)	36195	39	2006	0.05
NHDS Stripper Reboiler (02H-002)	36198	44.2	2006	0.05

EUG 26 New Fuel-Burning Equipment with Heat Input ≥ 100 MMBTUH

These sources are regulated under NSPS Subpart Ja and MACT Subpart DDDDD. The interheater (Point ID 39225) has discharges of approximately 55,800 ACFM and 380°F venting through an 8.3´ diameter stack at 125´ above grade. The capacity of this unit has historically been poorly documented. The rated capacity was increased from 141.8 to 155 MMBTUH, and the fuel sulfur limits of NSPS Subpart Ja was accepted. However, the increased rating was not accompanied with a physical change.

Source	Point ID	MMBTUH (HHV)	Heater Date	NOx lb/MMBTU (HHV)
CCR #1 Interheater (10H-113)	39225	155	2005	0.05
Naphtha Splitter Reboiler Heater 10H-105	6162	100	Pending	0.03
FCCU Charge B-2	6158	165	Pending	0.03

EUG 27 Existing Fuel-Burning Equipment with NO_X Limits

All fuel gas combustion devices (FGDs) are subject to NSPS Subpart J, effective June 30, 2008.

Stack	Height (ft)	Diameter (Ft)	Temp (°F)	Flow (ACFM)
DHTU	140	4.8	590	35,993
CCR Reboiler	124	4.5	500	22,000
CCR Heaters	124	5.8	550	103,300

The following list shows available information for heaters in this EUG.

Source	Point ID	MMBTUH (HHV)	Heater Date	NOx lb/MMBTU (HHV)
DHTU Reactor Charge 1H-101	6156	80	1972**	0.05
CCR Charge Heater 10H-101	6163	120	1972*	0.05
CCR Inter-heater #2-1 10H-102	6163	101	1972	0.15
CCR Interheater #2-2 10H-103	6163	25	1972	0.15
CCR Stabilizer Reboiler 10H-104	6162	85	1972*	0.05

* Low-NO_X burners installed in 2005.
**Low-NOx burners installed in 2011.

EUG-28: LPG Recovery Unit Fugitive VOC Leakage

EU	Point	Equipment	Estimated Number of Items	Installed Date
LPG	N/A	Fugitive VOC Leakage Components at LPG Recovery Unit	150 gas/vapor valves	2014 - 2015
			150 light liquid valves	
			5 heavy liquid valves	
			660 flanges	
			8 light liquid pumps	
			2 heavy liquid pumps	
			15 gas relief valves	

EUG 29 New Heaters (NSPS Subpart Ja)

This EUG contains new fuel-burning equipment with heat input less than 100 MMBTUH. These sources are all regulated under NSPS Ja and MACT Subpart DDDDD.

Source	Point ID	Burner Type	MMBTUH (HHV)	Heater Date	NOx lb/MMBTU (HHV)
CCR Helper Heater	N/A	ULNB	25	2015	0.03
NHDS Helper Heater	N/A	ULNB	10	2015	0.03
DHTU Helper Heater	N/A	ULNB	50	2015	0.03

EUG 30: ROSE Unit Fugitive VOC Leakage

EU	Point	Equipment	Estimated Number of Items	Installed Date
ROSE	N/A	Fugitive VOC Leakage Components at ROSE Unit	200 gas/vapor valves	2014 - 2015
			300 light liquid valves	
			70 heavy liquid valves	
			1,204 flanges	
			10 light liquid pumps	
			5 heavy liquid pumps	
			2 compressor seals	
			15 gas relief valves	

EUG 32: DHTU, NHDS Unit, Alky Unit, FCCU Regenerator Unit, and Naphtha Fractionation Column Fugitive VOC Leaks

EU	Point	Equipment	Estimated Number of Items	Installed Date
DHTU	N/A	Fugitive VOC Leakage Components at DHTU Unit	20 gas/vapor valves 45 light liquid valves 2 light liquid pumps 144 flanges 5 gas relief valves	2014 - 2015
NHDS	N/A	Fugitive VOC Leakage Components at NHDS Unit	20 gas/vapor valves 45 light liquid valves 2 light liquid pumps 144 flanges 5 gas relief valves	2014 - 2015
Alky	N/A	Fugitive VOC Leakage Components atAlky Unit	20 gas/vapor valves 45 light liquid valves 2 light liquid pumps 144 flanges 5 gas relief valves	2014 - 2015
FCCU Regenerator	N/A	Fugitive VOC Leakage Components at FCCU Regenerator Unit	50 gas/vapor valves 75 light liquid valves 3 light liquid pumps 268 flanges 6 gas relief valves	2014 - 2015
Naphtha Fraction-ation	N/A	Fugitive VOC Leakage Components at Naphtha Fractionation Column Unit	125 gas/vapor valves 125 light liquid valves 3 light liquid pumps 524 flanges 1 compressor seal 8 gas relief valves	2014 - 2015

EUG-33 Modified CDU Heater

Source	Point ID	Manu-facturer	Burner Type	No. of Burners	MMBTUH (HHV)	Heater Date	NOx lb/MMBTU (HHV)
ECDU Atmospheric Tower Heater	6155	To be decided	To be decided	To be decided	380	2018	0.061

EUG 34 Stationary SI Engines Subject to 40 CFR Part 63 Subpart ZZZZ

ID Number	HP	Description	Construction/ Modification Date
007-J-26G	75	Kohler 50RZB 4SRB emergency engine	2004
008-PA-50	75	Kohler 50RZGB-051 4SRB emergency engine	2003
050-G-1M	66	Kohler 20RZ-Q5 4SRB emergency engine	2002
004-G-1	104	Kohler 304Z-QS 4SRB emergency engine	2001
012-G-1M	421	Kohler 275RZD 4SRB emergency engine	2004

EUG 34a Stationary Engines Subject to 40 CFR Part 60 Subpart JJJJ

ID Number	HP	Description	Construction/ Modification Date
045-G-1M	360	Kohler 275 RZDB 4SRB emergency engine	2010
006-PE-80M	45	Kohler 25RZGB 4SRB emergency engine	2008

EUG 35 Stationary CI Engines Subject to 40 CFR Part 63 Subpart ZZZZ

ID Number	HP	Description	Construction/ Modification Date
009-PE-143	700	Cummins VT-1710-F CI emergency engine	1977
009-PE-144	262	John Deere 6081HF001 CI emergency engine	Pre-2002

EUG 35a Stationary Engines Subject to 40 CFR Part 60 Subpart IIII

ID Number	HP	Description	Construction/ Modification Date
033-EG-5320	700	Caterpillar C18 214-0021 CI emergency engine	2010
009-PE-152	380	Cummins CFP15E-F10 CI emergency engine	2014

EUG Plant-Wide Entire Facility

This EUG is established to cover all rules or regulations that apply to the facility as a whole.

V. EMISSIONS

A. New / Modified Units Emissions (East Refinery)

Emissions from the new heaters are based on continuous operation at rated heat input; NSPS Subpart Ja limits for SO_2 (162 ppm in RFG, 3-hour basis and 60 ppm in RFG, 365-day rolling average, NOx emissions of 0.03 lb/MMBTU and CO emissions of 0.04 lb/MMBTU from BACT requirements. All other factors are from Tables 1.4-1 and 2 of AP-42 (7/98). A heating value of 1,020 BTU/SCF was used for refinery fuel gas.

Fugitive VOC leakage calculations used estimated numbers of new components and emissions factors from EPA's "1995 Protocol for Equipment Leak Emission Estimates," Table 2-4. Control efficiencies are from Texas Commission on Environmental Quality (TCEQ) guidance.

FCCU regenerator emissions were based on the following factors, using a measured stack flow of 52,131 SCFM and estimate of 20,000 lb/hr coke burn-off:

Pollutant	Emission Factor	Factor Reference
NO_X	40 ppm hourly / 20 ppm annual	Consent Order requirement
CO	500 ppm	NSPS Subpart Ja limit
VOC	0.144 lb/1000 lb coke	Stack test
SO_2	50 ppm	NSPS Subpart Ja limit
PM_{10} / $PM_{2.5}$	1.0 lb/1000 lb coke	NSPS Subpart Ja limit

Modified CCR Unit: EUG-6

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
CCR	VOC Leakage CCR Unit	gas valves	20	0.059	97%	0.04	0.16
		lt liq valves	45	0.024	97%	0.03	0.14
		lt liq pumps	2	0.251	85%	0.08	0.33
		flanges	144	0.00055	30%	0.06	0.24
		gas relief valves	5	0.35	97%	0.05	0.23
TOTALS						**0.32**	**1.41**

Modified FCCU Regenerator: EUG-11

Process Rates	Pollutant	Emission Factor	Emissions	
			lb/hr	TPY
20,000 lb/hr coke burn-off ; Stack flow 52,121 SCFM	NO_X	40 ppm hourly / 20 ppm annual	15.2	33.2
	CO	500 ppm	115	505
	VOC	0.144 lb/1000 lb coke	2.9	12.6
	SO_2	50 ppm	26.4	115.6
	PM_{10} / $PM_{2.5}$	1.0 lb/1000 lb coke	20	87.6
	H_2SO_4		3.6	15.9

New Components in RFG System: EUG-16

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
	VOC Leakage New Components of RFG System	gas valves	365	0.059	97%	0.65	2.83
		flanges	824	0.00055	30%	0.32	1.39
		lt liq pumps	11	0.251	85%	0.41	1.81
		gas relief valves	36	0.35	97%	0.38	1.66
TOTALS						**1.76**	**7.69**

New Process Drains (Naphtha Fractionator): EUG-17

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
—	Process Drains at Naphtha Fractionator	Process drains	2	0.035	--	0.07	0.31

Naphtha Splitter Reboiler Heater 10H-105: EUG-26

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
100 MMBTUH	NO_X	0.03	3.00	13.1
	CO	0.04	4.00	17.5
	VOC	0.0054	0.54	2.36
	SO_2	0.026 hourly 0.0098 annual	2.64	4.28
	PM_{10} / $PM_{2.5}$	0.0075	0.75	3.26
	GHG	163.29	16,329	71,521

FCCU Charger Heater B-2: EUG-26

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
165 MMBTUH	NO_X	0.03	4.95	21.68
	CO	0.04	6.60	28.91
	VOC	0.0054	0.89	3.90
	SO_2	0.026 hourly 0.0098 annual	4.35	7.08
	PM_{10} / $PM_{2.5}$	0.0075	1.24	5.38
	GHG	163.29	26,943	118,100

LPG Unit: EUG-28

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
LPG	VOC Leakage at LPG Recovery Unit	gas valves	150	0.059	97%	0.27	1.16
		lt liq valves	150	0.024	97%	0.11	0.47
		hvy liq valves	5	0.00051	0%	0.01	0.01
		flanges	550	0.00055	30%	0.21	0.93
		lt liq pumps	8	0.251	85%	0.30	1.32
		hvy liq pumps	2	0.046	0%	0.09	0.40
		gas relief valves	15	0.35	97%	0.16	0.69
TOTALS						**1.14**	**4.99**

DHTU Helper Heater: EUG-29

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
50 MMBTUH	NO_X	0.03	1.50	6.57
	CO	0.04	2.00	8.76
	VOC	0.0054	0.27	1.18
	SO_2	0.026 hourly 0.0098 annual	1.32	2.14
	PM_{10} / $PM_{2.5}$	0.0075	0.37	1.63
	GHG	163.29	8,164	35,761

NHDS Helper Heater: EUG-29

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
10 MMBTUH	NO_X	0.03	0.30	1.31
	CO	0.04	0.40	1.75
	VOC	0.0054	0.05	0.24
	SO_2	0.026 hourly 0.0098 annual	0.26	0.43
	PM_{10} / $PM_{2.5}$	0.0075	0.07	0.33
	GHG	163.29	1,633	7,152

CCR Helper Heater: EUG-29

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
25 MMBTUH	NO_X	0.03	0.75	3.29
	CO	0.04	1.00	4.38
	VOC	0.0054	0.13	0.59
	SO_2	0.026 hourly 0.0098 annual	0.66	1.07
	PM_{10} / $PM_{2.5}$	0.0075	0.19	0.82
	GHG	163.29	4,082	17,880

Naphtha Fractionator Column: EUG-32

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
NAPH THA	VOC Leakage New Naphtha Fractionator Column	gas valves	125	0.059	97%	0.22	0.97
		lt liq valves	125	0.024	97%	0.09	0.39
		flanges	500	0.00055	30%	0.19	0.84
		lt liq pumps	3	0.251	85%	0.11	0.50
		gas relief valves	8	0.35	97%	0.08	0.37
		compr. Seal	1	1.400	85%	0.21	0.92
TOTALS						**0.98**	**4.29**

Modified DHTU Unit: EUG-32

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
DHTU	VOC Leakage DHTU Unit	gas valves	20	0.059	97%	0.04	0.16
		lt liq valves	45	0.024	97%	0.03	0.14
		lt liq pumps	2	0.251	85%	0.08	0.33
		flanges	144	0.00055	30%	0.06	0.24
		gas relief valves	5	0.35	97%	0.05	0.23
TOTALS						**0.32**	**1.41**

Modified NHDS Unit: EUG-32

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
NHDS	VOC Leakage NHDS Unit	gas valves	20	0.059	97%	0.04	0.16
		lt liq valves	45	0.024	97%	0.03	0.14
		lt liq pumps	2	0.251	85%	0.08	0.33
		flanges	144	0.00055	30%	0.06	0.24
		gas relief valves	5	0.35	97%	0.05	0.23
TOTALS						**0.32**	**1.41**

Modified FCCU Regenerator Unit: EUG-32

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
FCCU Regen	VOC Leakage FCCU Regenerator Unit	gas valves	50	0.059	97%	0.09	0.39
		lt liq valves	75	0.024	97%	0.05	0.24
		lt liq pumps	3	0.251	85%	0.11	0.50
		flanges	268	0.00055	30%	0.10	0.45
		gas relief valves	6	0.35	97%	0.06	0.28
TOTALS						**0.49**	**2.15**

Modified Alky Unit: EUG-32

EU	Description	Equipment	Number of Items	Emission Factor, lb/hr/source	Control Eff.	lb/hr	TPY
Alky	VOC Leakage Alky Unit	gas valves	20	0.059	97%	0.04	0.16
		lt liq valves	45	0.024	97%	0.03	0.14
		lt liq pumps	2	0.251	85%	0.08	0.33
		flanges	144	0.00055	30%	0.06	0.24
		gas relief valves	5	0.35	97%	0.05	0.23
TOTALS						**0.32**	**1.41**

CDU Atmospheric Tower Heater: EUG-33

Unit Capacity	Pollutant	Emission Factor, lb/MMBTU	Emissions	
			lb/hr	TPY
380 MMBTUH	NO_X	0.04	15.20	66.58
	CO	0.05	19.0	57.90
	VOC	0.0054	2.05	8.98
	SO_2	0.026 hourly 0.0098 annual	10.02	16.25
	PM_{10} / $PM_{2.5}$	0.0075	2.85	12.4
	GHG	163.29	62,050	271,780

Existing Units Emissions

Unless otherwise stated, all emission estimates in Section V reflect operations as reported in the 2005 and 2006 Inventory Turn-Around Documents. Additionally, most VOC emissions are non-HAP only, unless otherwise indicated. HAP emissions were calculated EUG by EUG in the memorandum associated with the initial TV permit, and the reader may peruse that memorandum for more information concerning the methods used. HAP emissions reported for 2006 will be presented in aggregate near the end of this Section V. Tanks shown as “Out of Service” or “Idle” had no activity in 2006. The “Contents” column of each table for tanks reflects information presented in the Turn-Around Document, and does not represent a classification or requirement. Assumptions and data used in calculating emissions for each EUG are reflected in the following analyses.

Fugitive VOC leakage calculations used estimated numbers of new components and emissions factors from EPA’s “1995 Protocol for Equipment Leak Emission Estimates,” Table 2-4. Control efficiencies are from TCEQ guidance.

EUG 3 MACT CC Group 2 Storage Vessels - Fixed Roof (FR)

These storage vessels are expected to have negligible VOC emissions (< 0.1 TPY apiece).

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity	VOC TPY
112	6195	2012	30'	110’	50,000	0.1
118	6201	1907	30'	96'	37,500	0.1
119	6202	1907	30'	96'	37,500	0.1
126	6263	1907	30'	96'	37,500	0,1
TOTAL						**0.4**

EUG 4 MACT CC Wastewater Tanks

Non-HAP VOC emissions of 3.19 TPY are calculated using the current version of EPA’s TANKS program for slop oil Tank #13 with 13.2 turnovers in 2006. All other tanks in this EUG have negligible emissions.

EUG 6 Continuous Catalytic Reforming Unit (CCR)

Emission sources at the CCR are included in other EUGs.

EUG 8 Fired Boilers

Calculations assume all four units are operated continuously at rated capacity of 233 MMBTUH each. Natural gas emission factors are taken from AP-42 (3/98), Tables 1.4-1 and 2, assuming 1,020 BTU/CF, except that SO_2 factors assume 60 ppmv H_2S in for RFG for a 365-day rolling average basis for tpy and 162 ppmv 3-hour average basis for lb/hr. The NO_X factors are taken from requirements imposed in the CD. A 365-day rolling average of 0.03 lbs per MMBTU is required, so pound per hour limits are not set for NO_X.

Boiler Emissions

		Each Boiler		Four Boiler Total
Pollutant	**Lb/MMCF**	**lb/hr**	**TPY**	**TPY**
NO_X	30.6	N/A	30.6	122
CO	84	19.2	84.0	336
$PM_{10}/PM_{2.5}$	7.6	1.74	7.60	30.4
SO_2	26.5 hourly 10.0 annual	6.14	9.96	39.8
VOC	5.5	1.26	5.50	22.0

Emission factors for HAP were also reviewed, using AP-42 (3/98), Table 1.4-3. Only those factors resulting in 0.01 TPY or more of any constituent are reported here. The following table shows all of these constituents, picking the higher value when both fuels resulted in emissions of any single constituent. Emission totals from the 2006 Turn-around document are shown for comparison. Note that 2006 data for benzene included oil combustion, which has been discontinued.

Constituent	CAS #	Emissions (TPY)	
		Potential	**2006**
Formaldehyde	50-00-0	0.30	0.21
Hexane	110-54-3	7.20	0.74
Benzene	91-20-3	0.01	0.10
Toluene	108-88-3	0.01	0.25

EUG 9 Fuel-Burning Equipment

Various process heaters share stacks. Stack parameters follow the equipment list. Natural gas emission factors are taken from AP-42 (3/98), Tables 1.4-1 and 2, assuming 1,020 BTU/CF, except that SO_2 factors assume 60 ppmv H_2S in for RFG for a 365-day rolling average basis for tpy and 162 ppmv 3-hour average basis for lb/hr. Note that actual heating values at certain units may vary widely from the standard mentioned. Because HFTR is unable to provide exact heat ratings for this equipment, the following emission estimates would not become more accurate through knowledge of the precise heating value of the fuel used by each heater. According to the CD, all heaters are affected facilities under NSPS Subpart J.

Source	Pollutant	Emission factor lb/MMCF	Emissions	
			lb/hr	TPY
CDU-vacuum	NO_X	100	12.0	52.6
	CO	84	8.2	36.1
	PM	7.6	0.7	3.3
	SO_2	26.5 hourly 10.0 annual	2.6	4.3
	VOC	5.5	0.5	2.4
FCCU-B-1	NO_X	100	4	17
	CO	84	3.2	14
	PM	7.6	0.3	1.3
	SO_2	59	2	10
	VOC	5.5	0.2	0.9
ISOM-unifiner	NO_X	100	4.2	18.4
	CO	84	3.5	15.1
	PM	7.6	0.3	1.4
	SO_2	26.5 hourly 10.0 annual	1.1	1.8
	VOC	5.5	0.1	1.1

Emission factors for HAP were also reviewed, using AP-42 (3/98), Table 1.4-3. Only those factors resulting in 0.01 TPY or more of any constituent are reported here.

Constituent	CAS #	TPY
Formaldehyde	50-00-0	0.13
Hexane	110-54-3	3.26
Benzene	71-43-2	0.01
Toluene	108-88-3	0.01

EUG 10 Sulfur Recovery Units

Emission factors for the SRU #1 set are based on a Reference Method stack test for carbon monoxide, CEMS for SO_X, and natural gas combustion factors from Tables 1.4-1 and 2 of AP-42 (7/98) for NO_X, PM_{10}, and VOC. Emission factors for the SRU #2 set are all taken from the same AP-42 tables, except for SO_X, which is taken from CEMS. Emissions of all pollutants were authorized in two construction permits; No. 98-021-C (M-15), which covered construction of the SCAN Unit, and No. 98-021-C (M-26), which covered the Low Sulfur Diesel Project. Emissions authorized by those permits were established based on the following considerations.

- A voluntary limit was taken on SRU #1 for SO_X to avoid PSD consequences in the SCAN project.
- A limit based on the NSPS Subpart J standard of 250 ppm of SO_X was applied to the maximum possible exhaust from the unit.
- NO_X limits for each unit were set based on the maximum 0.20 lbs/MMBTU limit of OAC 252:100-33-2(a) for new gas-fired fuel-burning equipment.
- Limits for CO, PM_{10}, and VOC were all based on the AP-42 tables mentioned earlier. Subsequent reference method testing of CO emissions from SRU #1 required that a new limit be authorized by Permit No. 98-021-TV (M-52).

The following table lists the limits currently in place, along with the emissions recorded in the 2006 Turn-around document. Note that the only limits at SRU #1 are an annual limit on SO_2, taken to avoid PSD in Permit No. 98-021-C (M-16) and the CO limit associated with Permit No. 98-021-TV (M-52). VOC numbers include volatile HAP.

SRU #1 Emissions					SRU #2 Emissions		
Pollutant	**Permit**		**2006**		**Permit**		**2006**
	lb/hr	**TPY**	**TPY**		**lb/hr**	**TPY**	**TPY**
SO_2		34.9	0.13		5.62	24.6	0.38
NO_X			1.15		2.42	10.6	2.32
PM_{10}			0.09		0.09	0.39	0.18
VOC			0.02		0.07	0.29	0.05
CO		99	48.4		5.55	24.31	1.95

EUG 12 Flares

Emission factors are found in Table 5.1-1 of AP-42 (1/95). Using 2008 refinery feed of 22,060,000 barrels yields the following results. The facility is required to utilize a Flare Gas Recovery Unit (FGRU) to comply with the flaring limits of NSPS Subpart Ja, so future emissions will be somewhat less than the historic values shown.

Pollutant	Emission factor (lb/1,000 barrels)	Emissions (TPY)
PM_{10}	Negligible	-0-
NO_X	18.9	297
CO	4.3	47.4
SO_2	26.9	208
VOC	0.8	8.82
H_2S	Eng. estimate	0.01

EUG 13 MACT EEEE Tanks

These small tanks have negligible emissions and would be considered to be insignificant activities, were they not affected facilities under MACT EEEE.

EUG 15 High Vapor Pressure Loading Operations

There are several loading racks that handle VOC materials. Emissions from the butane and propylene racks are routed to the refinery flare.

Emissions from the propylene rack are calculated in a series of steps that depend on the loading process itself. The truck is a pressure vessel and the factors of Section 5.2 of AP-42 do not apply. The only loss consideration is the possible contents of the flexible lines used in the loading process and the physical state (phase, pressure, etc.) of the contents of these lines. Thus, a fixed amount of loss may be assigned to each loading event. Total product can be divided by the capacity of each truck to calculate the number of loading events. Loss per event multiplied by the number of events yields total emissions. The maximum loading rate of 15,000 gallons per hour can be used to calculate a maximum hourly emission rate of 6.16 lbs/hr of VOC. The maximum sustained production rate of 800 barrels per day yields an annual potential of 6.90 TPY. Actual loading of 5.44 MM gallons for 2008 resulted in VOC emissions of 0.75 TPY.

A similar approach was taken in analyzing butane rack emissions except that no maximum rate is available. Actual loading of 38.7 MM gallons for 2008 resulted in 3.5 TPY of VOC emissions.

Propane rack loading losses are negligible.

EUG 16 Fugitive Emissions

Equipment leaks from the process units are included in this EUG. Piping and equipment associated with the cooling towers and with the wastewater system are included with the process units. Over 20,000 items were tabulated in the initial TV permit. There is at least one construction permit open and several modifications to the operating permit, all of which have the potential to slightly alter the total. The equipment count was detailed to process units and further refined to show type of service, such as gas, light liquid, etc., and finally divided as to components larger or smaller than two inches. Speciation of the VOC was based on testing or analysis of streams at each of the listed units. Total VOC was estimated at 838 TPY, HAP included, with the most highly-represented HAPs being hexane at 18.9 TPY, toluene at 18.0 TPY, and MTBE at 12.3 TPY.

EUG 17 Wastewater System

Emissions are calculated using EPA's WATER9 program for estimating air emissions from wastewater systems, "Air Emission Models Wastewater Treatment." The model was run using an outflow of 457,874,200 gallons (871 gpm) and measured concentrations of various constituents. Results are included in the EUG 16 totals.

EUG 18 Hydrocarbon Recovery System

Non-HAP VOC emissions too small to estimate were calculated using mass balance for the group of tanks involved, with total throughput of 2,500 gallons in 2008.

EUG 19 Cooling Towers

For the existing cooling towers, assuming drift to be 1.7 lbs/1,000 gals in these induced draft systems yields PM emissions of 62.2 TPY. This calculation of VOC PTE is based on factors found in Table 5.1-2 of AP-42 (1/95), using an aggregate circulation rate of 113,000 gpm. The 2008 emission inventory report showed entrained non-HAP VOC emissions of 19.4 TPY.

For Tower 7a, PM emissions were calculated with a flow of 20,000 GPM, a drift of 0.0015%, and a dissolved solids content of 2,430 ppm. VOC emissions were calculated using a factor of AP-42 (1/95), Section 5.1 at 3.68 TPY.

EUG 20 NSPS Kb Tanks (EFR) - MACT CC Group 1 Wastewater

Tank 476 was estimated to have emissions of 1.90 TPY of VOC, with a throughput limit of 683 MMgpy. Turnaround document emissions for 2006 follow. Data for Tank 478 were taken from Permit Application No. 2012-1062-TVR (M-2).

Tank No.	Throughput, 1,000 gallons	VOC Emissions (TPY)
476	436,175	1.18
478	547,500	0.04

EUG 21 Pressurized Spheres

There are no emissions from these pressurized tanks. Fugitive emissions from associated piping are included in the calculations for EUG 16 above.

EUG 22 Pressurized Bullet Tanks

There are no emissions from these pressurized tanks. Fugitive emissions from associated piping are included in the calculations for EUG 16 above.

EUG 23 MACT CC Group 2 Wastewater Tanks

There are negligible emissions from the tanks in this EUG.

EUG 24 Tanks Subject to NESHAP FF.

There are negligible emissions from the tank in this EUG.

<u>EUGs 25, 26, and 27 Fuel-Burning Equipment</u>

Emissions of particulate (PM_{10}), carbon monoxide (CO), and VOC from all new and existing equipment are calculated based on factors found in Tables 1.4-1 and 2 of AP-42 (7/98). Oxides of nitrogen (NO_X) for new units and for those units modified with low-NO_X burners is estimated based on vendor performance data. The NO_X factor for existing units not modified for such burners is taken to be the OAC 252:100-33-2(a) limit of 0.20 lbs/MMBTU for new equipment. This factor differs from the AP-42 factor used in annual emission inventories. The SO_2 factor assumes a maximum concentration of 60 ppmv H_2S in RFG for a 365-day rolling average basis for TPY, and 162 ppmv H_2S on a 3-hour average basis for lb/hr, which is the NSPS Subpart Ja standard, and stoichiometric conversion to SO_2. All refinery fuel gas (RFG) is assumed to have a heating value of 1,020 BTU/SCF.

EUG 25

Unit and heat rate	Pollutant	Emission factor	Emissions lb/hr	Emissions TPY
NHDS Charge heater 39 MMBTUH	SO_2	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	1.03	4.50
	NO_X	0.05 lb/MMBTU	4.95	8.54
	PM_{10}	7.6 lb/MMCF	0.29	1.27
	VOC	5.5 lb/MMCF	0.21	0.92
	CO	84 lb/MMCF	3.21	14.1
NHDS Stripper reboiler 44.2 MMBTUH	SO_2	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	1.17	5.10
	NO_X	0.05 lb/MMBTU	2.21	9.68
	PM_{10}	7.6 lb/MMCF	0.33	1.44
	VOC	5.5 lb/MMCF	0.24	1.04
	CO	84 lb/MMCF	3.64	15.9
SCAN charge heater 25.2 MMBTUH	SO_2	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	0.66	2.91
	NO_X	0.07 lb/MMBTU	1.76	7.73
	PM_{10}	7.6 lb/MMCF	0.19	0.82
	VOC	5.5 lb/MMCF	0.14	0.60
	CO	84 lb/MMCF	2.08	9.09

EUG 26

Unit and heat rate	Pollutant	Emission factor	Emissions lb/hr	Emissions TPY
CCR Interheater #1 155 MMBTUH	SO_2	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	4.09	17.9
	NO_X	0.05 lb/MMBTU	7.75	33.9
	PM_{10}	7.6 lb/MMCF	1.16	5.08
	VOC	5.5 lb/MMCF	0.85	3.73
	CO	84 lb/MMCF	13.0	57.0

EUG 27

Unit and heat rate	Pollutant	Emission factor	Emissions	
			lb/hr	**TPY**
CCR Charge heater 120 MMBTUH	SO_2	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	3.16	13.9
	NO_X	0.05 lb/MMBTU	6.00	26.3
	PM_{10}	7.6 lb/MMCF	0.89	3.92
	VOC	5.5 lb/MMCF	0.65	2.83
	CO	84 lb/MMCF	9.88	43.3
CCR Interheater #2-1 101 MMBTUH	SO_2	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	2.66	11.7
	NO_X	0.15 lb/MMBTU	15.5	66.4
	PM_{10}	7.6 lb/MMCF	0.75	3.30
	VOC	5.5 lb/MMCF	0.54	2.39
	CO	84 lb/MMCF	8.32	36.4
CCR Interheater #2-2 25 MMBTUH	SO_2	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	0.66	2.89
	NO_X	0.15 lb/MMBTU	3.75	16.4
	PM_{10}	7.6 lb/MMCF	0.19	0.82
	VOC	5.5 lb/MMCF	0.13	0.59
	CO	84 lb/MMCF	2.06	9.02
CCR Stabilizer reboiler 85 MMBTUH	SO_2	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	2.24	9.82
	NO_X	0.05 lb/MMBTU	4.25	18.6
	PM_{10}	7.6 lb/MMCF	0.63	2.77
	VOC	5.5 lb/MMCF	0.46	2.01
	CO	84 lb/MMCF	7.00	30.7
DHTU Charge heater 80 MMBTUH	SO_2	26.5 lb/MMBTU hourly 10.0 lb/MMBTU annual	2.11	9.24
	NO_X	0.05 lb/MMBTU	4.0	17.52
	PM_{10}	7.6 lb/MMCF	0.60	2.60
	VOC	5.5 lb/MMCF	0.44	1.89
	CO	84 lb/MMCF	6.59	28.8

EUGs 34, 34a, 35, and 35a Emergency Stationary Internal Combustion Engines

Engine emissions are based on 500 hours per year operations

EUG 34

Unit and HP	Pollutant	Emission factor	Emissions lb/hr	Emissions TPY
007-J-26G (75 HP; 0.6 MMBTU)	NOx	4.08 lb/MMBTU	2.45	0.61
	CO	0.557 lb/MMBTU	0.33	0.08
	VOC	0.118 lb/MMBTU	0.07	0.02
	$PM_{10}/PM_{2.5}$	0.01 lb/MMBTU	0.01	0.01
	SO_2	0.0006 lb/MMBTU	0.01	0.01
008-PA-50 (75 HP; 0.6 MMBTU)	NOx	4.08 lb/MMBTU	2.45	0.61
	CO	0.557 lb/MMBTU	0.33	0.08
	VOC	0.118 lb/MMBTU	0.07	0.02
	PM_{10}	0.01 lb/MMBTU	0.01	0.01
	SO_2	0.0006 lb/MMBTU	0.01	0.01
050-G-1M (66 HP; 0.53 MMBTU)	NOx	4.08 lb/MMBTU	2.15	0.54
	CO	0.557 lb/MMBTU	0.29	0.07
	VOC	0.118 lb/MMBTU	0.06	0.02
	PM_{10}	0.01 lb/MMBTU	0.01	0.01
	SO_2	0.0006 lb/MMBTU	0.01	0.01
004-G-1 (104 HP; 0.83 MMBTU)	NOx	4.08 lb/MMBTU	3.39	0.85
	CO	0.557 lb/MMBTU	0.46	0.12
	VOC	0.118 lb/MMBTU	0.10	0.02
	PM_{10}	0.01 lb/MMBTU	0.01	0.01
	SO_2	0.0006 lb/MMBTU	0.01	0.01
012-G-1M1 (421 HP; 3.37 MMBTU)	NOx	4.08 lb/MMBTU	13.70	3.44
	CO	0.557 lb/MMBTU	1.88	0.47
	VOC	0.118 lb/MMBTU	0.40	0.10
	PM_{10}	0.01 lb/MMBTU	0.03	0.01
	SO_2	0.0006 lb/MMBTU	0.01	0.01

EUG 34a

Unit and heat rate	Pollutant	Emission factor	Emissions lb/hr	Emissions TPY
045-G-1M (360 HP; 2.88 MMBTU)	NOx	2.21 lb/MMBTU	6.36	1.59
	CO	3.51 lb/MMBTU	10.11	2.53
	VOC	0.030 lb/MMBTU	0.09	0.02
	PM_{10}	0.01 lb/MMBTU	0.03	0.01
	SO_2	0.0006 lb/MMBTU	0.01	0.01
006-PE-80M (45 HP; 0.36 MMBTU)	NOx	4.08 lb/MMBTU	1.47	0.37
	CO	0.557 lb/MMBTU	0.20	0.05
	VOC	0.118 lb/MMBTU	0.04	0.01
	PM_{10}	0.01 lb/MMBTU	0.01	0.01
	SO_2	0.0006 lb/MMBTU	0.01	0.01

EUG 35

Unit and heat rate	Pollutant	Emission factor	Emissions lb/hr	Emissions TPY
009-PE-143 (700 HP; 5.6 MMBTU)	NOx	0.024 lb/hp-hr	16.80	4.20
	CO	0.055 lb/hp-hr	3.85	0.96
	VOC	0.0007 lb/hp-hr	0.49	0.12
	PM_{10}	0.0007 lb/hp-hr	0.49	0.12
	SO_2	0.0004 lb/hp-hr	0.28	0.07
009-PE-144 (216 HP; 1.73 MMBTU)	NOx	0.031 lb/hp-hr	6.70	1.67
	CO	0.0067 lb/hp-hr	1.44	0.36
	VOC	0.0025 lb/hp-hr	0.53	0.13
	PM_{10}	0.0022 lb/hp-hr	0.48	0.12
	SO_2	0.00205 lb/hp-hr	0.44	0.11

EUG 35a

Unit and heat rate	Pollutant	Emission factor	Emissions lb/hr	Emissions TPY
033-EG-5320 (700 HP; 5.6 MMBTU)	NOx	0.024 lb/hp-hr	16.80	4.20
	CO	0.055 lb/hp-hr	3.85	0.96
	VOC	0.0007 lb/hp-hr	0.49	0.12
	PM_{10}	0.0007 lb/hp-hr	0.49	0.12
	SO_2	0.0004 lb/hp-hr	0.28	0.07
009-PE-152 (380 HP; 3.04 MMBTU)	NOx	2.78 g/hp-hr	2.33	0.58
	CO	0.7 g/hp-hr	0.56	0.14
	VOC	0.10 g/hp-hr	0.08	0.02
	PM_{10}	0.09 g/hp-hr	0.08	0.02
	SO_2	0.0004 lb/hp-hr	0.15	0.04

Total Engine Emissions

Pollutant	lb/hr	TPY
NOx	74.60	18.66
CO	23.30	5.82
VOC	2.42	0.60
PM_{10}	1.65	0.45
SO_2	1.22	0.36

NET EMISSIONS CHANGES

The initial step in the process of determining net emissions changes was summing the post-project potential emissions for each new unit, each modified unit, and each unit with increased utilization. These totals exceeded the PSD levels of significance for NO_X, CO, VOC, SO_2, $PM_{2.5}/PM_{10}$, and GHG, requiring determination of net emissions changes.

Net emissions changes for the project were calculated by using the post-project potential emissions for each new unit, each modified unit, and each unit with increased utilization compared to the Baseline Actual Emissions (BAE) for each pollutant, except for SO_2, which uses Projected Actual Emissions (PAE). To remain under the 40 TPY SER for SO_2, the PAE for the SRUs was based on 25 ppmv SO_2 and the PAE for the FCCU regenerator was based upon 10 ppmv SO_2. (Reported actual SO_2 emissions have been well below these projected values.)

The BAE period for all pollutants was calendar years 2010 and 2011.

There were several contemporaneous projects:

- Numerous pipelines were constructed between the two refineries as part of the "integration" project.

- The DHTU was revamped to meet new diesel fuel sulfur standards.

- The CCR was upgraded to a higher throughput.

- Boilers 3 and 4 at the West Refinery have been shut down.

- Boiler 10 at the West Refinery was installed under a PSD permit; as a unit operating less than 2 years, BAE is equal to PAE, for a net change of zero in this latest expansion.

- Sulfur reduction projects: flare gas recovery at the West Refinery, NaSH/Amine Unit at the East Refinery, and sour gas fuel line interconnection; the BAE for fuel gas combustion units at the West Refinery uses NSPS Subpart J limits as required by Consent Decree.

- Coker blowdown project at West Refinery.

- "Benzap" (Mobile Source Air Toxics) Unit, which has been repurposed as the Naphtha Splitter Reboiler.

- Loading Terminal vapor combustion unit.

- Numerous older, grandfathered tanks have been replaced with newer tanks, mostly with floating roofs; despite the throughput increase, VOC emissions from tanks will decline from the BAE.

Baseline Actual Emissions

Unit	Point ID	NO_X TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
East Refinery								
DHTU Charge Heater 1H-101	6156	3.29	12.9	0.84	1.16	1.16	0.20	20,414
CCR Charge Heater 10H-101	6163	24.5	19.7	1.29	1.78	1.78	0.30	31,251
CCR #2-1 Interheater 10H-102	6163	12.8	10.4	0.68	0.94	0.94	0.16	16,428
CCR #2-2 Interheater 10H-103	6163	6.31	5.11	0.33	0.46	0.46	0.08	8,103
CCR Stabilizer Reboiler 10H-104	6162	3.30	0.09	0.51	0.70	0.70	0.12	12,236
Naphtha Splitter Reboiler Heater 10H-105	6162	0.32	0.67	0.044	0.06	0.06	0.027	1,059
CCR Interheater #1 10H-113	39225	14.7	31.0	2.03	2.80	2.80	0.48	49,103
Boiler #1	6150	3.61	39.1	2.56	3.53	3.53	0.59	62,043
Boiler #2	6150	5.10	42.1	2.75	3.80	3.80	0.62	66,720
Boiler #3	6151	2.34	40.5	2.65	3.66	3.66	0.62	64,305
Boiler #4	6151	4.88	37.4	2.45	3.38	3.38	0.55	59,303
Sulfur Recovery Unit / Tail Gas Treating Unit #1	6152	0.36	37.2	0.014	0.02	0.02	0.90	345
Sulfur Recovery Unit / Tail Gas Treating Unit #2	36200	3.00	1.80	0.12	0.16	0.16	0.19	2,852
NHDS Charge Heater 02H-001	36195	3.46	0.04	0.42	0.58	0.58	0.10	10,259
NHDS Stripper Reboiler 02H-002	36198	2.84	0.38	0.37	0.52	0.52	0.09	9,063
CDU Atmospheric Tower Heater	6155	84.4	57.9	3.79	5.24	5.24	1.30	91,888
CDU Vacuum Tower Heater	6155	41.6	28.5	1.87	2.58	2.58	0.64	45,258
FCCU Charge Heater B-2	6158	33.3	18.3	1.20	1.65	1.65	0.31	20,414
FCCU Regenerator	6153	3.08	75.1	0.094	30.2	30.2	9.17	158,360
Unifiner Charge Heater H-1	6167	7.31	6.02	0.39	0.54	0.54	0.091	9,554
Scanfiner Charge Heater 12H-101	23133	1.20	0.01	0.092	0.13	0.13	0.023	2,234
Tanks	Multiple	-	-	3.19	-	-	-	62
Equipment Leaks		-	-	204.3	0.27	0.027	-	267
Wastewater Treatment	---	-	-	240.0	-	-	-	-
HEP (Loading Terminal)								-
Tanks	Multiple	-	-	156.5	-	-	-	62
Loading/Unloading Racks (excluding Terminal)	---	-	-	3.62	-	-	-	-
Vapor Combustion Unit	6275	14.83	37.10	37.5	1.48	1.48	0.39	9,214
Fugitives	N/A	-	-	2.56	0.27	0.027	-	267

Baseline Actual Emissions - Continued

Unit	Point ID	NO_X TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
West Refinery								
#7 Boiler	#7 Boiler	46.9	20.3	1.33	1.84	1.84	0	32,261
#8 Boiler	#8 Boiler	69.0	29.9	1.96	2.71	2.71	0	47,469
#9 Boiler	#9 Boiler	53.4	31.4	2.06	2.84	2.84	0	49,843
#10 Boiler	#10 Boiler	39.0	77.4	5.07	7.00	7.00	9.17	122,776
CDU Atmospheric Tower Heater	CDU H-1	112	85.1	5.57	7.70	7.70	30.9	135,020
CDU #1 Vacuum Tower Heater	CDU H-2	30.6	25.2	1.65	2.28	2.28	46.7	39,951
CDU #2 Vacuum Tower Heater	CDU H-3	8.97	7.39	0.48	0.67	0.67	2.7	11,723
Unifiner Charge Heater	Unifiner H-2	9.03	4.96	0.32	0.45	0.45	1.69	7,867
Unifiner Stripper Reboiler	Unifiner H-3	13.2	7.24	0.47	0.66	0.66	2.46	11,491
No. 2 Platformer Charge Heater	#2 Plat PH-3	8.20	4.50	0.29	0.41	0.41	1.53	7,138
No. 2 Platformer Charge Heater	#2 Plat PH-4	9.93	5.45	0.36	0.49	0.49	0.68	8,649
Coker Drum Charge Heater	Coker B-1	11.6	10.6	0.70	0.96	0.96	0.01	16,887
Coker Pre-Heater	Coker H-3	5.31	4.86	0.32	0.44	0.44	0.004	7,708
LEU Raffinate Mix Heater	LEU H101	7.31	4.01	0.26	0.36	0.36	1.68	6,363
LEU Extract Mix Heater	LEU H-102	32.6	29.8	1.95	2.70	2.70	167	47,303
LEU Hydrotreater Charge Heater	LEU H-201	9.16	5.03	0.33	0.45	0.45	2.10	7,977
MEK – Wax Free Oil Heater	MEK H-101	36.3	19.9	1.30	1.80	1.80	0	31,595
MEK – Soft Wax Heater	MEK H-2	13.1	9.00	0.59	0.81	0.81	3.40	14,282
Loading / Unloading Racks	Multiple	-	-	6.40	0.90	0.11	-	-
Tanks	Multiple	-	-	78.3	-	-	-	73
Fugitive VOC Leakage	---	-	-	168.1	1.68	0.11	-	198
Wastewater Treatment	---	-	-	196.3	-	-	-	-
TOTAL BASELINE ACTUAL EMISSIONS		**792.1**	**883.4**	**1,146.3**	**103.0**	**100.2**	**287.0**	**1,357,638**

The FCCU is the only unit with significant sulfuric acid (H_2SO_4) emissions. Baseline actual emissions of sulfuric acid are stated at 12.1 TPY.

Post-Project Potential To Emit For NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG / SO_2 Projected Actual Emissions

Unit	Point ID	NO_X TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
East Refinery								
CCR Helper Heater	N/A	3.29	4.38	0.59	0.82	0.82	1.07	17,880
NHDS Helper Heater	N/A	1.31	1.75	0.24	0.33	0.33	0.43	7,152
DHTU Helper Heater	N/A	6.57	8.76	1.18	1.63	1.63	2.14	35,761
New Tanks	Multiple	-	-	0.86	-	-	-	20.7
Equipment Leaks – New Units	Multiple	-	-	17.0	-	-	-	348
DHTU Charge Heater 1H-101	6156	17.52	28.9	1.89	2.61	2.61	1.43	57,217
CCR Charge Heater 10H-101	6163	26.3	43.3	2.83	3.92	3.92	2.14	85,825
CCR #2-1 Interheater 10H-102	6163	66.4	36.4	2.39	3.30	3.30	1.8	72,236
CCR #2-2 Interheater 10H-103	6163	16.4	9.02	0.59	0.82	0.82	0.45	17,880
CCR Stabilizer Reboiler 10H-104	6162	18.6	30.7	2.01	2.77	2.77	1.51	60,793
Naphtha Splitter Reboiler Heater 10H-105	6162	13.1	17.5	2.36	3.26	3.26	1.78	71,521
CCR Interheater #1 10H-113	39225	33.9	55.9	3.66	5.06	5.06	2.76	110,858
Boiler #1	6150	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Boiler #2	6150	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Boiler #3	6151	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Boiler #4	6151	30.6	84.0	5.50	7.60	7.60	4.15	166,644
Sulfur Recovery Unit / Tail Gas Treating Unit #1	6152	4.91	99.0	0.13	0.18	0.18	14.0	3,604
Sulfur Recovery Unit / Tail Gas Treating Unit #2	36200	10.6	24.3	0.29	0.39	0.39	9.84	7,787
NHDS Charge Heater 02H-001	36195	8.54	14.1	0.92	1.27	1.27	0.69	27,893
NHDS Stripper Reboiler 02H-002	36198	9.68	15.9	1.04	1.44	1.44	0.79	31,612
CDU Atmospheric Tower Heater	6155	66.58	57.90	8.98	12.40	12.40	6.77*	271,780
CDU Vacuum Tower Heater	6155	52.6	36.1	2.36	3.26	3.26	1.78	71,521
FCCU Charge Heater B-2	6158	21.68	28.91	3.90	5.38	5.38	2.94	118,010
FCCU Regenerator	6153	33.2	505	12.614	87.6	87.6	23.1	293,591
Unifiner Charge Heater H-1	6167	18.4	15.1	0.99	1.37	1.37	0.75	30,039
Scanfiner Charge Heater 12H-101	23133	7.73	9.09	0.60	0.82	0.82	0.45	18,023
Existing Tanks	Multiple	-	-	3.19	-	-	-	80.5
Existing Equipment Leaks (incl. modified units)	---	-	-	212.1	0.27	0.027	-	334
Wastewater Treatment	13409	-	-	200.0	-	-	-	-

*SO_2 6.77 TPY is a Projected Actual Emission.

Post-Project Potential To Emit For NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG / SO_2 Projected Actual Emissions - Continued

Unit	Point ID	NO_X TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
West Refinery								
PDA/ROSE Heater	N/A	10.0	13.3	1.79	2.48	2.48	3.25	54,356
Hydrogen Plant Reformer Heater	---	16.4	21.9	2.95	4.08	4.08	5.34	89,401
Hydrogen Plant Process Emissions	---	-	4.06	-	-	-	-	75,991
New Tanks	---	-	-	18.4	-	-	-	20.7
Equipment Leaks – New Units	---	-	-	6.28	-	-	-	258
#7 Boiler	#7 Boiler	131	54.1	3.54	4.90	4.90	2.67	107,282
#8 Boiler	#8 Boiler	131	54.1	3.54	4.90	4.90	2.67	107,282
#9 Boiler	#9 Boiler	131.4	54.1	3.54	4.90	4.90	2.67	107,282
#10 Boiler	#10 Boiler	39.0	77.4	5.07	7.00	7.00	9.17	153,484
CDU Atmospheric Tower Heater	CDU H-1	330	146	9.54	13.2	13.2	30.9	288,946
CDU #1 Vacuum Tower Heater	CDU H-2	35.0	28.9	1.89	2.61	2.61	46.7	57,217
CDU #2 Vacuum Tower Heater	CDU H-3	18.9	15.6	1.02	1.41	1.41	2.68	30,897
Unifiner Charge Heater	Unifiner H-2	24.1	13.2	0.87	1.20	1.20	1.69	26,248
Unifiner Stripper Reboiler	Unifiner H-3	39.1	21.5	1.41	1.94	1.94	2.46	42,555
No. 2 Platformer Charge Heater	#2 Plat PH-3	23.8	13.1	0.86	1.18	1.18	1.53	25,962
No. 2 Platformer Charge Heater	#2 Plat PH-4	19.6	16.2	1.06	1.46	1.46	1.91	32,041
Coker Drum Charge Heater	Coker B-1	23.7	21.6	1.42	1.96	1.96	1.07	42,913
Coker Pre-Heater	Coker H-3	12.7	11.6	0.76	1.05	1.05	0.57	23,030
LEU Raffinate Mix Heater	LEU H101	14.7	8.08	0.53	0.73	0.73	1.68	16,021
LEU Extract Mix Heater	LEU H-102	59.1	54.1	3.54	4.90	4.90	166	107,282
LEU Hydrotreater Charge Heater	LEU H-201	14.7	8.08	0.53	0.73	0.73	2.10	16,021
MEK – Wax Free Oil Heater	MEK H-101	53.2	29.2	1.91	2.64	2.64	1.44	57,932
MEK – Soft Wax Heater	MEK H-2	25.8	17.7	1.16	1.60	1.60	3.40	35,045
Loading / Unloading Racks	Multiple	-	-	6.45	0.90	0.11	-	-
Existing Tanks	Multiple	-	-	78.3	-	-	-	94.5
Existing Equipment Leaks (incl. modified units)	---	-	-	170.0	1.68	0.11	-	248
Wastewater Treatment	15943	-	-	196.3	-	-	-	-

Post-Project Potential To Emit For NO_x, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG / SO_2 Projected Actual Emissions - Continued

Unit	Point ID	NO_x TPY	CO TPY	VOC TPY	PM_{10} TPY	$PM_{2.5}$ TPY	SO_2 TPY	GHG TPY
HEP (Loading Terminal)								
New Tanks	Multiple	-	-	19.4	-	-	-	20.7
Equipment Leaks – New Units	16	-	-	7.09	-	-	-	348
Loading/Unloading Racks (excluding Terminal)	---	-	-	3.62	-	-	-	-
Existing Tanks	Multiple	-	-	156.5	-	-	-	20.7
Vapor Combustion Unit	6275	14.8	37.1	37.5	1.48	1.48	0.39	11,518
Existing Equipment Leaks (incl. modified units)	16	-	-	2.56	0.27	0.027	-	347.5
TOTAL POST-PROJECT EMISSIONS		**1,727.71**	**2,098.93**	**1,254.04**	**238.50**	**235.65**	**376.74**	**3,588,406**

The FCCU is the only unit with significant sulfuric acid (H_2SO_4) emissions. Projects actual emissions of sulfuric acid are stated at 15.9 TPY.

Project Emissions Changes

Pollutant	PAE TPY	BAE TPY	Difference TPY	PSD Levels of Significance, TPY	Netting Required?
NO_x	1,727.71	792.14	935.57	40	Yes
CO	2,098.93	883.36	1,215.57	100	Yes
VOC	1,254.04	1,146.27	107.77	40	Yes
PM_{10}	238.50	103.06	135.44	15	Yes
$PM_{2.5}$	235.65	100.21	135.44	10	Yes
SO_2	376.74	286.975	89.77	40	Yes
GHG	3,588,406	1,357,638	2,230,768	75,000	Yes
H_2SO_4	15.9	12.1	3.8	7	No

PSD Netting

Project	**NOx TPY**	**CO TPY**	**VOC TPY**	**PM_{10} TPY**	**$PM_{2.5}$ TPY**	**SO_2 TPY**	**GHG TPY**
Projected Actual Emissions	1,727.71	2,098.93	1,254.03	238.50	235.65	376.74	3,588,406
Baseline Actual Emissions	-792.1	-883.4	-1146.3	-103.0	-100.2	-287.0	-1,357,638
East Removed Tanks	--	--	-0.79	--	--	--	-62
HEP Removed Tanks	--	--	-38.8	--	--	--	--
HEP Removed Thermal Oxidizer	-2.47	-6.18	-8.00	-0.56	-0.56	--	--
HEP Added Tanks	--	--	8.33	--	--	--	19.4
Vapor Combustor	14.8	37.1	37.45	1.48	1.48	0.39	9,214
West Removed Tanks	--	--	-57.4	--	--	--	-72.7
West Heaters – Subpart J to Subpart Ja Fuel	--	--	--	--	--	-42.79	--
West Boilers 3 and 4 Removed	-196	-57.7	-3.78	-5.22	-5.22	-20.7	-91,495
West PDA Propane Compressor Electrified	-0.86	-3.44	-1.00	-0.17	-0.17	-0.005	-1,089
West Unifiner H2 Recycle Compressor Electrified	-0.35	-4.62	-1.34	-0.23	-0.23	-0.01	-1,462
West Plat PH-1/2 Heater Removed	-31.5	-17.3	-1.13	-1.56	-1.56	-5.89	-27,415
West Plat PH-5 Heater Removed	-17.4	-11.3	-0.74	-1.02	-1.02	-0.01	-17,861
West Plat PH-6 Heater Removed	-7.69	-4.81	-0.32	-0.44	-0.44	-0.004	-7,632
West Plat PH-7 Heater Removed	-3.65	-2.00	-0.13	-0.18	-0.18	-0.68	-3,177
West #2 Cooling Tower Circulating Pump Electrified	-0.74	-2.94	-0.85	-0.15	-0.15	-0.004	-189
West #3 Cooling Tower Circulating Pump Electrified	-1.78	-7.11	-2.07	-0.36	-0.36	-0.01	-19.3
West #6 Cooling Tower Spray Pump Electrified	-2.04	-8.14	-2.37	-0.41	-0.41	-0.01	--
West #6 Cooling Tower Circulating Pump Electrified	-0.83	-3.32	-0.97	-0.17	-0.17	-0.005	-42.5
West #3 Cooling Tower Replacement	--	--	-3.68	-5.12	-0.03	--	--
	--	--	3.68	3.30	0.02	--	--
West #10 Boiler	39.0	77.4	5.07	7.00	7.00	9.17	122,788
NET EMISSIONS CHANGES	**724.10**	**1,239.5**	**36.7**	**119.9**	**121.7**	**37.8**	**2,242,311**
Subject to PSD?	**Yes**	**Yes**	**No**	**Yes**	**Yes**	**No**	**Yes**

VI. BACT REVIEW

OAC 252:100-8-31 states that BACT "*means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Director, on a case-by-case basis, taking into account energy, environmental, and economic impacts or other costs, determines is achievable for such source or modification…."* A BACT analysis is required to assess the appropriate level of control for each new or physically modified emission unit at which a net emissions increase would occur for each pollutant that exceeds the applicable PSD Significant Emissions Rate (SER).

The U.S. EPA has stated its preference for a "top-down" approach for determining BACT and that is the methodology used for this permit review. After determining whether any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the available control technologies, including the most stringent control technology, for a similar or identical source or source category. If the proposed BACT is equivalent to the most stringent emission limit, no further analysis is necessary.

If the most stringent emission limit is not selected, further analyses are required. Once the most stringent emission control technology has been identified, its technical feasibility must be determined; this leads to the reason for the term "available" in Best Available Control Technology. A technology that is available and is applicable to the source under review is considered technically feasible. A control technology is considered available if it has reached the licensing and commercial sales stage of development. In general, a control option is considered applicable if it has been, or is soon to be, developed on the same or similar source type. If the control technology is feasible, that control is considered to be BACT unless economic, energy, or environmental impacts preclude its use. This process defines the "best" term in Best Available Control Technology. If any of the control technologies are technically infeasible for the emission unit in question, that control technology is eliminated from consideration.

The remaining control technologies are then ranked by effectiveness and evaluated based on energy, environmental, and economic impacts beginning with the most stringent remaining technology. If it can be shown that this level of control should not be selected based on energy, environmental, or economic impacts, then the next most stringent level of control is evaluated. This process continues until the BACT level under consideration cannot be eliminated by any energy, environmental, or economic concerns.

The five basic steps of a top-down BACT review are summarized as follows:

- Step 1. Identify Available Control Technologies
- Step 2. Eliminate Technically Infeasible Options
- Step 3. Rank Remaining Control Technologies by Control Effectiveness
- Step 4. Evaluate Most Effective Controls Based on Energy, Environmental, and Economic impacts
- Step 5. Select BACT and Document the Selection as BACT

In Step 1 in a “top down” analysis, all available control options for the emission unit in question are identified. Identifying all potential available control options consists of those air pollution control technologies or control techniques with a practical potential for application to the emission unit and the regulated pollutant being evaluated.

In Step 2, the technical feasibility of the control options identified in Step 1 are evaluated and the control options that are determined to be technically infeasible are eliminated. Technically infeasible is defined where a control option, based on physical, chemical, and engineering principles, would preclude the successful use of the control option on the emission unit under review due to technical difficulties. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 of the “top-down” analysis is to rank all the remaining control options not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, there would be no need to provide cost and other detailed information. Once the control effectiveness is established in Step 3 for all feasible control technologies identified in Step 2, additional evaluations of each technology, based on energy, environmental, and economic impacts, are considered to make a BACT determination in Step 4. The energy impact of each evaluated control technology is the energy benefit or penalty resulting from the operation of the control technology at the source. The costs of the energy impacts either in additional fuel costs or the cost of lost power generation impacts the cost-effectiveness of the control technology.

The second evaluation to be reviewed for each control technology remaining in Step 4 is the environmental evaluation. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology. The third evaluation addresses the economic evaluation of the remaining control technologies. The cost to purchase and to operate the control technology is analyzed. The capitol and annual operating costs are estimated based on established design parameters or documented assumptions in the absence of established designed parameters. The cost-effectiveness describes the potential to achieve the required emission reduction in the most economical way. It also compares the potential technologies on an economic basis.

In Step 5, BACT is selected for the pollutant and emission unit under review. BACT is the highest ranked control technology not eliminated in Step 4. The U.S. EPA has consistently interpreted statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether it is conducted in a “top-down” manner. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those that provide the maximum degree of emission reduction. Second, any decision to require a lesser degree of emission reduction must be justified by an objective analysis of energy, environmental, and economic impacts. As stated in the BACT definition, in no case can the maximum available emission rate for the sources exceed the New Source Performance Standard (NSPS) emission rate for the source, or cause an exceedance of the National Ambient Air Quality Standards (NAAQS). Therefore, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate below those specified by the NSPS and the ambient impact cannot exceed the NAAQS. The new or modified emission sources for this project that are subject to BACT are new process heaters, and new components that will be installed for new or modified process units.

Potentially applicable emission control technologies were identified by researching PSD permits recently issued by ODEQ for the ConocoPhillips Ponca City Refinery and other refineries, the U.S. EPA control technology database, technical literature, control equipment vendor information, and by using process knowledge and engineering experience. Manufacturers were contacted to provide information regarding emission guarantees. The RACT/BACT/LAER Clearinghouse (RBLC), a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies that have been approved in PSD permits as BACT for numerous types of process units. Process units in the database are grouped into categories by industry. Additional sources of potentially applicable emission control technologies include the California Air Resource Board (CARB) BACT determinations database. These sources were reviewed in order to supplement ODEQ permit review, vendor information, and RBLC search results.

Technical literature and guidance documents consulted for the BACT evaluations include:

- New Source Review Workshop Review Manual (Draft, October 1990);
- EPA's "Alternate Control Techniques Document for NOx Emissions" (June 1994);
- EPA's Air Pollution Technology Fact Sheets (2003);
- Emission Estimation Protocol for Petroleum Refineries, Version 2.1.1 (May 2011);
- EPA's Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources (AP-42, January 1995);
- PSD and Title V Guidance for Interim Permitting Guidance for Greenhouse Gases (March 2011); and
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Industry (October 2010).

A. New / Modified Process Heaters

1. NOx BACT Review

The CDU Atmospheric Tower Heater (380 MMBTUH) and the FCCU Charge Heater B-2 (165 MMBTUH) will not have a net emissions increase in NOx emissions, therefore, are not part of this analysis. After installation of Ultra-Low NOx burners, potential emissions of NOx are less than the baseline emissions, therefore, the unit will not have a net emissions increase. The heaters undergoing BACT review are: Naphtha Splitter Reboiler (10-105, 100 MMBTUH), DHTU Helper Heater (50 MMBTUH), NHDS Helper Heater (10 MMBTUH), and CCR Helper Heater (25 MMBTUH).

NOx emissions are generated from the high temperature dissociation of atmospheric nitrogen molecules and their subsequent reaction with oxygen to form nitrogen oxide (NO) or nitrogen dioxide (NO_2) (thermal NOx) and from chemically bound nitrogen in the fuel (fuel NOx). Thermal NOx is primarily formed at temperatures above 2,400°F; therefore, limiting the temperature of the flame can control its generation. Fuel NOx is formed when the fuel nitrogen is converted to hydrogen cyanide and then oxidized to form NO that further oxidizes in the atmosphere to NO_2. Since the first step of the oxidation occurs in the combustion chamber, providing an oxygen-deficient atmosphere in the combustion chamber can significantly reduce NO, and thereby NO_2 formation. Some combustion processes can be modified to minimize NOx emissions by reducing peak flame temperature, gas residence time in the flame zone, and oxygen concentration in the flame zone.

Step 1. Identify Available Control Technologies
A variety of technologies and techniques exist for control of NOx emissions from process heaters, which have the primary purpose of transferring heat to a process through exchangers. These include add-on control devices, and techniques to minimize NOx formation. The following is a list of equipment and add-on control technologies that were identified for controlling NOx emissions from process heaters and boilers.

- Low-NOx burners (LNB);
- Ultra Low-NOx Burners (ULNB);
- Flue Gas Recirculation (FGR);
- Selective Non-Catalytic Reduction (SNCR);
- Non-Selective Catalytic Reduction (NSCR);
- Selective Catalytic Reduction (SCR); and
- EMX™/SCONOX.

These technologies can be used alone or in combination, along with good combustion practices, to minimize NOx emissions. For example, lower emitting burners can be combined with add-on controls or combustion techniques, such as ULNB with SCR or SNCR, LNB with SCR or SNCR, and LNB with FGR.

Step 2. Eliminate Technically Infeasible Options
The Step 1 technologies were reviewed to determine which are technically feasible, to eliminate technically infeasible options. Some options have significant limitations in refining applications as compared to other technologies that render them infeasible and remove them from further consideration. These include EMX/SCONOX, NSCR, and FGR.

<u>EMX™/SCONOX</u>
The EMX™ catalyst is the latest generation of SCONOX technology. EMX™ is a multi-pollutant catalyst that does not require ammonia. While this technology has been demonstrated on units firing pipeline quality natural gas, there is no practical experience with operating on flue gas streams from refinery gas-fired equipment. At this time, EMX™ is not being used in any commercial refinery situation with equipment using a sulfur-bearing fuel gas stream such as refinery fuel gas because SO_2 will contaminate the catalyst and reduce efficiency over time. Additionally, the mechanical complexity of EMX™ increases in rough proportion to the heat duty rating of the unit. For larger commercial scale units, a large number of mechanical dampers must operate reliably every several minutes under hot and corrosive conditions to divert the flow of flue gas and regenerating hydrogen gas through segments of the catalyst beds. The challenge presented by this demanding design feature is aggravated by the fact that refinery fuel gas

combustion products have a higher potential corrosive acid concentration than natural gas combustion products.

The specified EMX™ catalyst operating temperature range of 300 to 700°F is also a practical limitation for use with refinery process heaters. The typical exhaust temperature range is significantly higher for refinery process heaters and boilers. The EMX™ catalyst technology is not usable unless the tolerated temperature range is increased or the exhaust temperature of the heaters is controlled.

EMX™ also creates an increase in system pressure drop that results in a substantial operating cost penalty. It is estimated that the net power incremental requirement due to higher catalyst bed pressure drop is about 1.8 times that associated with a comparable SCR system.

Because of the lack of commercial refinery experience, the catalyst's sensitivity to sulfur compounds, and mechanical limitations, EMX™ is deemed to be technically infeasible for the refinery process heaters.

Non-Selective Catalytic Reduction (NSCR)

NSCR is a flue gas treatment technology that is similar to the catalytic controls on modern automobiles. Precious metal catalysts, such as platinum, are used to promote reactions that reduce most nitrogen oxides (NO) in the exhaust gases to molecular nitrogen (N_2). Likewise, the catalyst will simultaneously convert over 98% of the NOx and CO and most of the unburned HC emissions according to the NSCR [unbalanced] reactions below:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2$$
$$NOx + CO \rightarrow CO_2 + N_2$$
$$H_2 + O_2 \rightarrow H_2O$$
$$HC + \frac{1}{2} O_2 \rightarrow H_2O + CO_2$$
$$NOx + H_2 \rightarrow H_2O + N_2$$

These reactions can only occur in this manner when the oxygen content of the exhaust is controlled to less than 1% vol. (typically about 0.5% vol.), which is accomplished by attaching an air/fuel controller (lambda sensor) to maintain the chemically correct (or stoichiometric) air/fuel ratio (AFR), such that all the fuel and oxygen in the mixture are consumed on combustion, and is typically referred to as a rich-burn or stoichiometric operation. The formulas above show that CO must be present in the exhaust gas in order for the NOx to be reduced to N_2. The refinery heaters operate in a lean burn (i.e., oxygen rich) environment where the O_2 content is substantially greater than 1% vol. There would not be enough CO present in the exhaust stream to effectively react the NOx to N_2. In addition, oxygen will adsorb on the catalyst and block the reaction. Therefore, NSCR is deemed technically infeasible for the refinery heaters and boilers.

FGR

Flue gas recirculation (recovery) involves the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. Internal FGR, used primarily in ULNB, involves recirculation of the hot O_2-depleted flue gas from the heater into the combustion zone using burner design features. External FGR, usually used with LNB, requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner wind box. Flue gas recirculation has not been demonstrated to function efficiently on process heaters that are subject to highly variable loads and that burn fuels with variable heat value. There are significant technical differences between the proposed process heaters and those combustion sources where flue gas recirculation has been demonstrated in practice. Thus, FGR has been eliminated as BACT for NOx reduction for the new process heaters proposed by HFTR.

Step 3. Rank Remaining Control Technologies by Control Effectiveness

The remaining options are ranked based on effectiveness.

Technology	Control Efficiency %
ULNB + SCR	85-99
LNB + SCR	80-99
ULNB + SNCR	75-95
LNB + SNCR	50-99
LNB	<40
ULNB	60-70
SCR	70-90
SNCR	30-50
No control	---

Step 4. Evaluate Remaining Options

The remaining top-ranked technologies are evaluated in this section, including their effectiveness, and any energy, environmental, and economic impacts.

LNB

The use of LNB is considered as a baseline NOx control technology, since NSPS Subpart Ja specifies a NOx limit of 0.04 lb/MMBTU, 30-day average. LNB technology uses advanced burner design to reduce NOx formation through the restriction of oxygen, flame temperature, and/or residence time. The two types of LNB include staged fuel and staged air burners. Staged fuel burners are particularly useful for NOx reduction in refinery process heaters. The burners separate the combustion zone into two regions, with lower combustion temperature in the first zone that reduces overall oxygen, with fuel injected into the second zone to reduce overall formation of thermal NOx. As a stand-alone control technology for a new heater, ULNB would be considered more effective for NOx emission control. However, LNB can be considered in conjunction with other add-on controls.

ULNB

There are several designs of ULNB currently available. These burners combine two NOx reduction steps into one burner; typically staged air with internal flue gas recirculation (IFGR) or staged fuel with IFGR, without any external equipment. In staged air burners with IFGR, fuel is mixed with part of the combustion air to create a fuel rich zone. High-pressure atomization of the fuel creates the recirculation. Secondary air is routed by means of pipes or ports in the burner block to optimize the flame and complete combustion. Thus the average oxygen concentration is reduced in the flame without reducing the flame temperatures below that which is necessary for optimal combustion efficiency. This design is predominately used with liquid fuels. Modern ULNB technology is available at a NOx emission rate of 0.03 lb/MMBTU for the size range of new process heaters proposed for the project.

SCR alone or SCR with ULNB or LNB

SCR is a post-combustion NOx control technology. In SCR, ammonia (NH_3) diluted with air or steam is injected into the flue gas upstream of a catalytic reactor. On the catalyst surface, the NH_3 reacts with NOx to form molecular nitrogen and water.

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

The SCR process requires a reactor vessel, a catalyst, and an ammonia storage and injection system. The SCR system requires ammonia in the presence of a catalyst. The presence of the catalyst effectively reduces the ideal reaction temperature for NOx reduction to between 475 and 850°F and increases the surface area available for NOx reduction. As a postcombustion process, the SCR system is usually installed to receive flue gas after it has left the combustion chamber. The exact location of the SCR reactor will vary depending upon what other type of pollution control systems are also present. Therefore, the applicability of SCR is limited to heaters that have both a flue gas temperature appropriate for catalytic reaction and space for the catalyst bed large enough to provide sufficient residence time for the reaction to occur. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NOx concentration, the exhaust temperature, the ammonia injection rate, the type of catalyst, and the presence of catalyst poisons, such as particulate matter and SO_2.

The EPA report "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic compounds at Tier 2/Gasoline Sulfur Refinery Projects" (John Seitz, January 19, 2001) served as the basis for SCR cost effectiveness calculations. The complete report, including economic analyses, is available at www.epa.gov/region7/air/nsr/nsrmemos/t2bact.pdf. The EPA report analyzed four burner sizes (10, 50, 75, and 150 MMBTUH) which are comparable to heaters proposed in this application. 90% NOx control was evaluated. Costs were then increased by the consumer price index relative to 2001, a factor of 1.336. The costs, $/ton, decrease as unit size increases, but all costs exceeded $10,000 per ton additional NOx controlled over baseline. It is agreed that these costs are excessive and SCR may be rejected.

Burner Size	Incremental Costs of SCR ($/ton) 2014 $
10	43,920
50	15,333
75	12,641
150	10,369

Catalyst systems promote partial oxidation of hydrogen sulfide to sulfur dioxide which combines with water to form sulfur trioxide and sulfuric acid (H_2SO_4). SCR units typically achieve 70 to 90% NOx reduction with an ammonia exhaust concentration (ammonia slip) of 5 to 10 parts per million by volume on a dry basis (ppmvd) at 15% oxygen. Additional environmental concerns are caused by the formation of secondary particulate from the ammonia reagent. The phenomenon can be more pronounced as ammonia injection rates must be increased and ammonia slip increases as the catalyst deactivates over time. There are also safety issues with the transportation, handling and storage of ammonia. Ammonia is a toxic substance whose storage above certain quantities requires the development of a Risk Management Plan (RMP). SCR can be used in combination with ULNB or LNB to increase overall NOx control efficiency to greater than 90%. While use of SCR can marginally increase NOx control effectiveness over LNB or ULNB technology, SCR has significant technical, economic, energy and environmental impacts, and thus, has been eliminated from consideration.

<u>SNCR alone or SCNR with ULNB or LNB</u>

SNCR describes a process by which NOx is reduced to molecular nitrogen (N_2) by injecting an ammonia or urea ($CO(NH_2)_2$) spray into the post-combustion area of the unit. Typically, injection nozzles are located in the upper area of the furnace and convective passes. Once injected, the urea or ammonia decomposes into NH_3 or NH_2 free radicals, reacts with NOx molecules, and reduces to nitrogen and water. These reactions are endothermic and use the heat of the burners as energy to drive the reduction reaction. The ammonia and urea reduction equations are shown following.

For ammonia: $4\ NO + 4\ NH_3 + O_2 \rightarrow 4N_2 + 6\ H_2O$

$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$

For urea: $4NO + 2\ CO(NH_2)_2 + O_2 \rightarrow 4N_2 + 2CO_2 + 4\ H_2O$

Both ammonia and urea have been successfully employed as reagents in SNCR systems and have certain advantages and disadvantages. Ammonia is less expensive than urea and results in substantially less operating costs at comparable levels of effectiveness. Urea, however, is able to penetrate further into flue gas streams, making it more effective in larger scale burners and combustion units with high exhaust flow rates. In addition, ammonia is a toxic substance whose storage above certain quantities requires the development of a Risk Management Plan (RMP). SNCR is considered a selective chemical process because, under a specific temperature range, the reduction reactions described above are favored over reactions with other flue gas components. Although other operating parameters such as residence time and oxygen availability can significantly affect performance, temperature remains one of the most prominent factors affecting SNCR performance.

The EPA report "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects" (John Seitz, January 19, 2001) served as the basis for SNCR cost-effectiveness calculations. SNCR was considered by EPA in the draft version of this report (issued for public comment March 14, 2000) and available at www.epa.gov/NSR/ttnnsr01/gen/refbact.pdf. SNCR was discarded from the final version of this report since SNCR alone was found to be inferior to ultralow NOx burner (at a higher cost) and SNCR plus ultralow NOx burner was found to be economically inferior to SCR plus ultralow

NOx burner. In addition, the combination of SNCR plus ultralow NOx burner had not been demonstrated so the performance level is uncertain. For purposes of our current application the SNCR costs are taken from the March 14, 2000 draft report and updated in the same manner that SCR costs were updated for the January 19, 2001 final report (the main update being the inclusion of a 1.5% fuel penalty). The control level from these reports of 0.015 lb NOx/MMBTU for SNCR plus ultralow NOx burner has not been demonstrated, but is assumed in the cost-effectiveness calculations. Three burner sizes were analyzed for costs using the factors in the EPA report, all with excessive costs for NOx control:

Burner Size	Incremental Costs of SNCR ($/ton) 2014 $
50	25.648
75	22,589
125	19,610

The SNCR process requires the installation of reagent storage facilities, a system capable of metering and diluting the stock reagent into the appropriate solution, and an atomization/injection system at the appropriate locations in the combustion unit. The reagent solution is typically injected along the post-combustion section of the combustion unit. Injection sites around the unit must be optimized for reagent effectiveness and must balance residence time with flue gas stream temperature. For ammonia, the optimum reaction temperature range is 1,600 to 2,000°F, while optimum urea reaction temperature ranges are marginally higher at 1,650 to 2,100°F. Although the overall chemistry is identical to that used in the SCR system, the absence of a catalyst results in several differences. The un-catalyzed reaction requires a higher reaction temperature and is not as effective. SCR can be used in combination with ULNB or LNB to increase overall NOx control efficiency to greater than 75-90%. While use of SNCR can marginally increase NOx control effectiveness over LNB or ULNB technology, and the technology is more economical than SCR with fewer energy and environmental impacts, the technology is still not considered economically cost-effective, and thus, has been eliminated from consideration.

Step 5. Select BACT and Document the Selection as BACT

The proposed heaters for this project (Naphtha Splitter Reboiler, DHTU Helper Heater, NHDS Helper Heater, and CCR Helper Heater,) are small ($\leq$ 100 MMBTUH) and are related to process units downstream of crude units. The following table presents a summary of selected BACT determinations for NOx emissions for similar process heaters within the last six years. The RBLC database indicates both proposed and achieved in practice emission rates of 0.03 to 0.08 lb/MMBTU NOx for similar sized units using ULNB and LNB technology and less than 100 MMBTUH. The RBLC does contain heaters with lower emission limits (i.e., 0.0125 to 0.02 lb/MMBTU), but these heaters utilize SCR controls, are large, and are mainly in nonattainment areas. Since ULNB provides the highest remaining feasible control, BACT has been proposed as ULNB at an emission rate of 0.03 lb/MMBTU (3-hour average) for the new process heaters. SCR and NSCR are economically infeasible and have adverse energy and environmental impacts given the size and nature of the proposed heaters. Therefore, the proposed ULNB controls with an emission factor of 0.03 lb /MMBTU NOx is selected as BACT.

Summary of Selected BACT Determinations for NO_X for Refinery Process Heaters, <250 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
PremCor Refining Group Valero Port Arthur Refinery	TX-0847	6825A, N65, PSDTX49M1, GHGPSDT	09/16/18	Heater EPN E-02-843	248	Refinery fuel gas	0.015	SCR and Good Combustion
CHS McPherson Refinery	KS-0032	C-13055	12/14/15	Coker Unit Heater	Not Listed	Refinery fuel gas	0.03	None listed
Holly Refinery and Marketing - Tulsa	OK-0170	2012-1062-C(M-6)PSD	11/12/15	H-205 Process Heater	100	Refinery fuel gas	0.03, (3-hour average)	ULNB
Phillips 66 Alliance	LA-0283	PSD-LA-696(M-3)	8/14/15	Low Sulfur Gasoline Feed No. 1	168	Refinery fuel gas	10.08 lb/hr; 0.04 (annual average)	None listed
Holly Refinery and Marketing - Tulsa	OK-0166	2010-599-C(M-3)PSD	4/20/15	Process Heater, PDA Revamp to ROSE	10, 25, 42, 50, 248	Refinery fuel gas	0.03, (3-hour average)	ULNB
Holly Refinery and Marketing - Tulsa	OK-0167	2012-1062-C(M-6)PSD	4/20/15	CDU Atmospheric Heater, four process heaters	10, 25, 42, 50, 248	Refinery fuel gas	0.03, (3-hour average)	ULNB
Lima Refining	OH-0362	P0114527	12/23/13	Vacuum Unit II Heater	102.3	Refinery fuel gas	0.03 (365-day rolling avg.)	ULNB
Diamond Shamrock Refining	TX-0720	PSDTX861M3	12/20/13	Vacuum Heater, naphtha charge heater	88, 33.3	Refinery fuel gas	0.035, 0.038	LNB
BP-Husky	OH-	P0111667	9/20/13	Vacuum Furnace Heater,	150, 247,	Refinery fuel	0.04 (30-day	None listed

Summary of Selected BACT Determinations for NO_X for Refinery Process Heaters, <250 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Refining	0357			Coker 3 Furnace, A-Diesel Hydrotreater Furnace, Vacuum Furnace	22.8, 150	gas	rolling average); 1.6 lb/hr (0.07); 0.065; 0.04 (30-day average)	
Holly Refining Woods Cross Refinery, UT	N/A	DAQE-IN101230041-12	July 2012	New – Reactor Charge Furnace, FCCU #2 Feed Heater, Asphalt Heaters, Heater Oil Furnace	42.1, 45, 0.8, 14	Refinery fuel gas	0.04 (3-hour average)	ULNB
Holly Refining Woods Cross Refinery, UT	N/A	DAQE-IN101230041-12	July 2012	New – Reactor Charge Furnace, Vacuum Furnace Heater	99, 130	Refinery fuel gas	0.02 (3-hour average)	LNB + SCR
Sinclair Refinery	WY-0071	MD-12620 (draft)	10/15/12 (project cancelled)	New - BSI Heater	50	Refinery fuel gas	0.025 (3-hr average)	ULNB
Sinclair Refinery	WY-0071	MD-12620 (draft)	10/15/12	581 Crude Heater	233	Refinery fuel gas	0.03 (3-hr average)	ULNB

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Sinclair Refinery	WY-0071	MD-12620 (draft)	10/15/12	Existing – Naphtha Splitter Heater; Hydrocracker H5 Heater; #1 HDS Heater	46.3, 44.9, 33.4	Refinery fuel gas	0.035 (3-hr average)	ULNB
Alliance Refinery	LA-0197	PSD-LA-696	7/21/09	Feed Heater	138.12	Refinery fuel gas	0.04 (1-hr average)	ULNB
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M5) (draft)	11/17/09	CPF Heaters H-39-03 & H-39-02	68	Refinery fuel gas	0.05 (3 - one-hr test avg.)	LNB
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M5) (draft)	11/17/09	Heaters (2008-1 - 2008-9)	36, 108, 123, 122, 122	Refinery fuel gas	0.03 (no-preheat) or 0.04 (air preheated) (three 1-hr Test Average)	ULNB
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M5) (draft)	11/17/09	Heaters	135, 86, 24, 52, 86, 100, 83, 100, 83	Refinery fuel gas	0.04 (3 - one-hr test avg.)	ULNB
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M5) (draft)	11/17/09	DHT Heaters (4-81, 5-81)	70	Refinery fuel gas	0.08 (3 - one-hr test avg.)	LNB

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Hunt Refinery Tuscaloosa	AL-0242	X063A, X066A, X067A, & X070A	9/28/09	Existing Modified Process Heaters	57, 49.4, 34.7, 98.3, 69.3, 78.2, 60.9, 254	Refinery fuel gas	0.035	ULNB
Chevron Products, Pascagoula Refinery	MS-0089	1280-00058	4/14/09	Lube Hydrocracker Feed Heater (Ck-003); Feed Preparation Unit Vacuum Column Feed Heater (Ck-004); ldw/Hdf Reactor Feed (Ck-005); Idw/Hdf Vacuum Column Feed Heater (Ck-006)	73.25, 73.95, 54.53, 51	Refinery fuel gas	0.045 (3-hr rolling average); 0.03 (3-day average)	ULNB
ConocoPhillips, Ponca City Refinery	OK-0136	2007-042-C PSD	2/9/09	Nh-1 New Naphtha Splitter Reboiler, NH-3 CTU Vacuum Heater, NH-4 CTU Crude Heater, NH-5 CTU Tar Stripper Heater	131.3, 45, 125, 98	Refinery fuel gas	0.03 (annual average)	ULNB
ConocoPhillips, Billings Refinery	MT-0030	2619-24	11/19/08	No. 2 H2 Heater	215	Refinery fuel gas	0.030	ULNB

Facility	RBLC #	Permit #	Permit Date	Unit Name	Rating (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
ConocoPhillips, Billings Refinery	MT-0030	2619-24	11/19/08	Vacuum Heater, Crude Heater	58, 165	Refinery fuel gas	0.039 (preheated) annual average	ULNB
Sunoco Inc., Tulsa Refinery	OK-0126	98-014-C(M-14)PSD (permit cancelled)	5/27/08	Process Heaters	44, 57.3	Refinery fuel gas	0.03 (3-hour average)	ULNB
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	Sulfur Recovery Hot Oil Heater, Hydrocracker Fractionator Furnace, Hydrocracker Reboiler, Rose2 Hot Oil Heater	9.6, 9.6, 35, 120	Refinery fuel gas	0.03 (3-hour rolling avg.)	ULNB
Marathon Petroleum Co., Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	GME Naphtha Hydrotreater Reactor Charge Heater, GME Naphtha Stripper Reboiler Heater, GME KHT Reactor Charge Heater, GME KHT Stripper Reboiler Heater, GME HCU Train 1 &2 Heaters	75.7, 138.4, 73.8, 121.8, 85.1, 85.1	Refinery fuel gas	0.03 lb/MMBTU annual average	ULNB

2. CO BACT Review

The CDU Atmospheric Tower Heater (380 MMBTUH) will not have an increase in CO emissions due to a permit limit, therefore, is not part of the CO analysis. Installation of Ultra-Low NOx burners reduced CO emissions on TPY basis, therefore, the unit has not been "modified" since "modification" means a physical or operational change which results in an **increase** in emissions. The heaters undergoing BACT review are: Naphtha Splitter Reboiler (10-105, 100 MMBTUH), DHTU Helper Heater (50 MMBTUH), NHDS Helper Heater (10 MMBTUH), CCR Helper Heater (25 MMBTUH), and the FCCU Charge Heater B-2 (165 MMBTUH).

Carbon monoxide is a product of the chemical reaction between carbonaceous fuels and oxygen. CO occurs as the product of combustion in fuel-rich mixtures. In fuel-lean mixtures, CO can result due to poor mixing of fuel and air or because of low temperatures in the combustion zone.

Step 1. Identify Available Control Technologies
A search of the RBLC and literature sources identified the following technologies for control of CO emissions from process heaters:

- Good Combustion Practice;
- Ultra-Low NOX Burners (ULNB);
- Regenerative Thermal Oxidation (RTO); and
- Regenerative Catalytic Oxidation (RCO).

Good Combustion Practice
Good combustion practice includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air, temperature, residence time, and mixing are incorporated in the combustion design and operation, CO emissions are minimized. The design of modern, efficient combustion equipment is such that there is adequate turbulence in the flue gas to ensure good mixing, a high temperature zone (greater than 1,800°F) to complete burnout, and sufficient residence time at the high temperature (one to two seconds). Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions.

ULNB
ULNB technology has developed to provide increasing lower levels of NOx emissions. However, when operated using good combustion practices, ULNB can also provide significant reductions in CO emissions.

Regenerative Thermal Oxidation
Thermal oxidizers combine temperature, time, and turbulence to achieve complete combustion. Thermal oxidizers are equivalent to adding another combustion chamber where more oxygen is supplied to complete the oxidation of CO. The waste gas is passed through burners, where the

gas is heated above its ignition temperature. Thermal oxidation requires raising the flue gas temperature to 1,300 to 2,000°F in order to complete the CO oxidation. Depending on specific furnace and thermal oxidizer operational parameters (fuel gas heating value, excess oxygen in the flue gas, flue gas temperature, and oxidizer temperature) raising the flue gas temperature can require an additional heat input of 10 to 25% above the process heater heat input. Also, depending on the design of the thermal oxidizer, emissions of SO_2, NOx and PM_{10} / $PM_{2.5}$ can be 10 to 25% higher than emissions without a thermal oxidizer.

Regenerative Catalytic Oxidation

Catalytic oxidation allows complete oxidation to take place at a faster rate and a lower temperature than is possible without the catalyst. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 feet per second (fps) to 30 fps. Catalytic oxidizers typically operate at 650 to 1,000°F. This can require from 0 to 10% additional fuel and a resulting similar increase in other pollutant emissions. Catalytic oxidizers cannot be used on waste gas streams containing significant amounts of particulate matter as the particulate deposits foul the catalyst and prohibit oxidation. High temperatures can also accelerate catalyst deactivation; however, that is normally not a concern with flue gas from process heaters and boilers.

Step 2. Eliminate Technically Infeasible Options

A search of the RBLC database indicated that thermal and catalytic oxidation has rarely been applied to process heaters or boilers. Typically, higher concentrations of CO in the pollutant stream are needed to justify the use of thermal oxidation and catalytic oxidation. However, neither control option can be eliminated as technically infeasible. Therefore, all of the technologies mentioned above will be examined for energy, environmental, and economic impacts.

Step 3. Rank Remaining Control Technologies by Control Effectiveness

The remaining options are ranked based on effectiveness.

Technology	Control Efficiency %
Good Combustion Practices	Base case
ULNB	25-75
Regenerative Thermal Oxidizer	75-95
Regenerative Catalytic Oxidation	75-95

Step 4. Evaluation of Remaining Control Technologies Based on Energy, Environmental, and Economic Impacts

The technologies for CO emission controls are evaluated in this section, including their effectiveness, and any energy, environmental, and economic impacts.

A review of BACT determinations for refinery heaters did not identify the use of add-on controls as achieved in practice. Instead, low-NOx burners have been used – many which also provide for low CO emissions.

A range of costs is based on EPA's Air Pollution Control Technology Fact Sheet for regenerative incinerators (www.epa.gov/ttn/catc/dir1/fregen.pdf). From a baseline of 0.082 lb CO/MMBTU (AP-42), the proposed ultralow-NOx burners will reduce emissions to an estimated 0.04 lb CO/MMBTU. For cost-effectiveness calculations it is assumed that the RTO or RCO can reduce CO by an additional 90%.The add-on control equipment is sized based on air flow, which varies from about 2,000 scfm for a 10 MMBTUH heater to 27,000 scfm for a 125 MMBTUH heater. Annualized costs [2002 basis] have been estimated to range from $8 - $33 per scfm for an RTO and $11 - $42 per scfm for a RCO. Using the average of the ranges, the incremental cost effectiveness is determined to be approximately $37,500/ton CO controlled by an RTO and approximately $48,500/ton CO controlled by a RCO. There is no bright line rule for cost-effectiveness of CO controls, but since incremental cost effectiveness of the add-on controls is two orders of magnitude greater than the cost effectiveness of for the ultra-low NOx burner the RTO and RCO control costs are not considered cost effective.

<u>RTO</u>
Installation costs and operating costs for RTO (mostly from the 10 to 25% increase in fuel consumption) can be significant. In addition, the use of a thermal oxidizer can significantly increase the emissions of NOx from the process heaters. A search of the RBLC indicated that thermal oxidation has not been selected as BACT for control of CO from small process heaters. Therefore, based on the additional use of energy, the increase in emissions of other pollutants, the associated costs, and no previous documentation of thermal oxidation as BACT; thermal oxidation is eliminated from further consideration.

<u>RCO</u>
Cost levels for RCO are also considered to be economically infeasible for BACT. Also, an environmental consideration is the disposal of spent catalyst, which is considered a hazardous material. A search of the RBLC and recently issued permits in attainment areas indicated that catalytic oxidation was rarely selected as BACT. Therefore, based on the additional use of energy, the possible increase in emissions of other pollutants, the associated costs, and no previous documentation of catalytic oxidation as BACT; catalytic oxidation is eliminated from consideration as BACT for this project.

<u>ULNB</u>
The DHTU Helper Heater, NHDS Helper Heater, CCR Helper Heater, and FCCU Charge Heater) are small to medium ($\leq$200 MMBTUH) and are related to process units downstream of crude units. The following table presents a summary of selected BACT determinations for CO emissions for similar process heaters within the last six years. A review of the RBLC database indicated that use of ULNB was selected as BACT for a number of PSD permits. These determinations were usually made on the basis that use of ULNB was BACT for NOx and would also be selected as BACT for CO. As the ULNB technology has achieved lower emissions of NOx, the burners have also provided lower emissions of CO. Recent BACT determinations for small process heaters <100 MMBTUH with ULNB and/or good combustion practices have shown CO emissions ranging from 0.04 to 0.08 lb/MMBTU.

Good Combustion Practices

Good combustion practice is the industry standard for CO control of process heaters and boilers. Operators control CO emissions by maintaining various operational combustion parameters. Modern combustion equipment has instrumentation to adjust for changes in air, draft, and fuel conditions. There is no increased energy requirement or increased pollutants with good combustion practice. The RBLC database lists this option as a prevalent form of BACT for controlling CO emissions from process heaters and boilers. CO emissions using this method will be 0.04 lb/MMBTU for Ultra-Low NOx burners.

Step 5. Select BACT and Document the Selection as BACT

The new process heaters (Naphtha Splitter Reboiler, DHTU Helper Heater, NHDS Helper Heater, CCR Helper Heater, and FCCU Charge Heater) for the project will be equipped with ULNB. HFTR will also follow good combustion practices. The combination of ULNB and good combustion practice is selected as BACT, at the emission rate of 0.04 lb CO/MMBTU.

The following regulations contained within 40 CFR 60 were reviewed with regards to the new process heaters, and CO emissions and NOx emissions discussed in the last section:

- Subpart J – Standards of Performance for Petroleum Refineries;
- Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007; and
- Subpart Dc – Small Industrial-Commercial-Institutional Steam Generating Units that Commenced Construction After June 9, 1989.

NSPS Subpart Ja includes a NOx emission limit for process heaters with rated capacities greater than 40 MMBTUH of 40 ppm NOx by volume, dry basis corrected to 0% excess air, on a 24-hour rolling average basis, which is approximately equivalent to 0.042 lbs NOx/MMBTU. The NOx emission limit proposed for the new heaters is more stringent, and therefore compliant with the currently-stayed NSPS Subpart Ja limit. Subpart Ja does not include CO limits for fuel gas combustion devices such as the new heaters. NSPS Subpart J does not include NOx or CO emission limits for fuel gas combustion devices. In addition, the regulations are not applicable to these heaters because of their date of manufacture. Subpart Dc does not include NOx or CO emission limits for gas-fired boilers. The only requirements for these boilers are initial notification and recordkeeping of the fuel combusted during each calendar month. Lastly, there are no currently applicable MACT standards with limits for NOx or CO.

Summary of Selected BACT Determinations for CO for Refinery Process Heaters, <250 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Name	Size (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
PremCor Refining Group Valero Port Arthur Refinery	TX-0847	6825A, N65, PSDTX49M1, GHGPSDT	09/16/18	Heater EPN E-02-843	248	Refinery fuel gas	0.04	Good combustion practices
Holly Refinery and Marketing - Tulsa	OK-0170	2012-1062-C(M-6)PSD	11/12/15	Process Heater	100	Refinery fuel gas	0.04, (3-hour average)	Good combustion practices
Holly Refinery and Marketing - Tulsa	OK-0167	2012-1062-C(M-6)PSD	4/20/15	CDU Atmospheric Heater, four process heaters	10, 25, 42, 50, 248	Refinery fuel gas	0.04, (3-hour average)	ULNB and gas fuel
Lima Refining	OH-0362	P0114527	12/23/2013	Vacuum Unit II Heater	102.3	Refinery fuel gas	0.04 (365-day rolling avg.)	ULNB
HFTR Woods Cross Refinery, UT	n/a	DAQE-IN101230041-12	July 2012	New – Reactor Charge Heater, FCCU#2 Feed Heater, Asphalt Heaters, Heater Oil Furnace	42.1, 45, 0.8, 14	Refinery fuel gas	0.08 (one-hour average)	ULNB, good combustion practices
Sinclair Refinery	WY-0071	MD-12620 (draft)	10/15/12	Existing Naphtha Splitter Heater; Hydrocracker HS Heater; #1 HDS Htr	50, 46.3, 44.9, 33.4	Refinery fuel gas	0.04 (3-hr average)	ULNB, good combustion practices
Valero	LA-	PSD-LA-	11/17/09	CPF Heaters H-39-	68, 36, 70	Refinery fuel	0.08 (one-hr	ULNB, good

Facility	RBLC #	Permit #	Permit Date	Name	Size (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Refining St. Charles Refinery	0213	619(M-5)(draft)		03 and H-39-02 Heaters 2008-1 – 2008-9 DHT Heaters 4-81 and 5-81		gas	average)	combustion practices
Total Refining – Port Arthur	TX-0539	PSD-TX-1073M1	11/6/09	VDU Heater; KNHT Charge Heater; DHT-3 Charge Heater	99, 42, 50	Refinery fuel gas	0.07 (one-he average)	Good burner technology
ConocoPhillips, Ponca City Refinery	OK-0136	2007-042-C PSD	2/9/09	NH-1 New Naphtha Splitter Reboiler	131.3, 45, 125, 98	Refinery fuel gas	0.04 (annual average)	ULNB, good combustion practices
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	ROSE 2 Hot Oil Heater	9.6, 9.6, 35, 120	Refinery gas	0.09 (3-hour rolling avg.)	ULNB, gaseous fuel combustion only
Marathon Petroleum CO LLC Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	Platformer Heater Cells No. 1-3, and HCU Fractioner Heater	75.7, 138.4, 73.8, 121.8, 85.1, 85.1	RFG	0.04 (3-run average)	ULNB, Proper design, operation, and good engineering practices
BP-Husky Refining	OH-0357	P0111667	9/20/13	2 Crude Furnaces, process heater	225, 150, 77	RFG	0.06	LNB
Sinclair Refinery	WY-0071	MD-12620	10/15/12	581 Crude heater	233	RFG	0.04	ULNB, good combustion practices

Facility	RBLC #	Permit #	Permit Date	Name	Size (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
ConocoPhillips, Ponca City Refinery	OK-0136	2007-042-C PSD	2/9/09	No. 4 CTU heater	125	RFG	0.04	ULNB, good combustion practices
Navajo Refining Company, Artesia Refinery	NM-0050	PSD-NM-195-M25	12/14/07	ROSE 2 Hot Oil Heater	120	RFG	0.06 (3-hour)	ULNB, gaseous fuel combustion only
Marathon Petroleum CO LLC Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	A&B Vacuum Tower Heaters	155.2	RFG	0.04 (30-day)	Proper design and operation; good engineering practices

Summary of Selected BACT Determinations for PM for Refinery Process Heaters, <250 MMBTUH

Facility	RBLC #	Permit #	Permit Date	Name	Size (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
PremCor Refining Group Valero Port Arthur Refinery	TX-0847	6825A, N65, PSDTX49M, GHGPSDT	09/16/18	Heater EPN E-02-843	248	Refinery fuel gas	0.0075	Use of gas fuel; Good combustion practices
ExxonMobil Beaumont Refinery	TX-0832	PSDTX768M1, SPDTX799, PSDTX802	1/9/18	F-2001 Kero HDT Charge Heater, F-2002 Kero HDT Stripper Reboiler, F-3001 Diesel DHDT Charge Heater, F-3002 Diesel DHDT Stripper Reboiler	85.5, 66.5	Natural Gas and Refinery Gas	0.49 lb/hr (0.0078)	Good combustion practices, Use of low sulfur gaseous fuel
CHS McPherson Refinery	KS-0032	C-13055	12/14/15	Cker Unit Heater	Not Listed	Refinery fuel gas	0.008	None listed
Holly Refinery and Marketing - Tulsa	OK-0170	2012-1062-C(M-6)PSD	11/12/15	H-205 Process Heater	100	Refinery fuel gas	0.0075 (3-hr average)	Good combustion practices
Holly Refinery and Marketing - Tulsa	OK-0167	2012-1062-C(M-6)PSD	4/20/15	Process Heater, PDA Revamp to ROSE	76	Refinery fuel gas	0.0075	Use of gas fuel

Facility	RBLC #	Permit #	Permit Date	Name	Size (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
Holly Refinery and Marketing - Tulsa	OK-0167	2012-1062-C(M-6)PSD	4/20/15	CDU Atmospheric Heater, four process heaters	10, 25, 42, 50, 248	Refinery fuel gas	0.0075	Use of gas fuel
Lima Refining	OH-0362	P0114527	12/23/2013	Vacuum Unit II Heater	102.3	Refinery fuel gas	0.0075	Good combustion practices
ConocoPhillips, Billings Refinery	MT-0030	2619-24	11/19/08	Crude Heater, Vacuum Heater, No. 2 H2 Heater	165, 58, 215	Refinery fuel gas	0.0075	Good combustion practices; Use of clean burning fuels
BP-Husky Refining	OH-0357	P0111667	9/20/13	Vacuum Furnace Heater, Crude Furnaces (2)	150, 225	Refinery fuel gas	0.0075	Continuous oxygen trim system; Tune-up every 5 years
BP-Husky Refining	OH-0357	P0111667	9/20/13	Coker and Naphtha Treater Heaters	77	Refinery fuel gas	0.02	Limit from State Rule
Valero Refining St. Charles Refinery	LA-0213	PSD-LA-619(M5)	11/17/09	CPF Heaters H-39-03 & H39-02	68, 90	Refinery fuel gas	0.0074	Good combustion practices
Total Refining – Port Arthur	TX-0539	PSD-TX-1073M1	11/6/09	Coker Unit Heaters, VDU Heater, KNHT Charge Heater, DHT-3 Charge Heater	211, 99, 42, 50	Refinery fuel gas	0.0074	Good burner technology
Hunt Refining, Tuscaloosa Refinery	AL-0242	X063A, X066A, X067A & X070A	9/28/09	Existing Modified Process Heaters	57, 49.4, 34.7, 98.3, 69.3, 78.2, 60.9, 254	Refinery fuel gas	0.0075	Good combustion practices

Facility	RBLC #	Permit #	Permit Date	Name	Size (MMBTUH)	Primary Fuel	Limit (lb/MMBTU)	Technology
ConocoPhillips, Billings Refinery	MT-0030	2619-24	11/19/18	Crude Heater, Vacuum Heater, No. 2 H2 Heater	165, 58, 215	Refinery fuel gas	0.0075	Good combustion practices; Use of clean burning fuels

Summary of Selected BACT Determinations for GHG for Process Heaters, <250 MMBTUH

RBLC ID	Facility	State	Permit Issuance Date	Name	BACT Limit
OK-0166	Holly Refinery and Marketing - Tulsa	OK	4/20/15	Process Heater, PDA Revamp to ROSE	146 lbs CO_2e per MMBTU
OK-0167	Holly Refinery and Marketing - Tulsa	OK	4/20/15	CDU Atmospheric Heater, four process heaters	146 lbs CO_2e per MMBTU
OH-0362	Lima Refining	OH	12/23/13	Vacuum Unit II Heater	54,151 tons, rolling 12 months (120.8 lbs CO_2e per MMBTU at 102.3 MMBTUH)
OH-0357	BP-Husky Refining	OH	9/20/13	Refinery Process Heaters	125.4 lbs CO_2e per MMBTU (Rolling 12-Months, 150 and 225 MMBTUH heaters)
ND-0031	Dakota Prairie Refining	ND	02/21/13	Distillate Hydrotreater Reboiler	15733 tons/year (130.6 lb CO_2e / MMBTU at 27.5 MMBTUH)

3. PM_{10} & $PM_{2.5}$ from New / Modified Process Heaters BACT Review (Including CDU Heater and FCCU Charge Heater)

PM_{10} is particulate matter (PM) less than 10 microns in diameter produced by combustion. PM_{10} consists of two parts, filterable and condensable. Filterable PM_{10} is the material that is captured on the filter used in the EPA Method 5 test. Condensable PM_{10} is particulate that passes through the filter as a gas and is measured using EPA Reference Method 202. According to AP-42, filterable PM emissions from gaseous fuels such as refinery fuel gas are typically lower than emissions from solid fuels. Particulate matter from refinery gas or natural gas combustion is usually composed of larger molecular weight hydrocarbons that have not been fully combusted. Based upon the literature sources reviewed, nearly all particulate from refinery gas or natural gas combustion sources is $PM_{2.5}$. Therefore, for the BACT analysis for process heaters, $PM_{2.5}$ and PM_{10} are considered equivalent. The heaters undergoing BACT review are: Naphtha Splitter Reboiler (10-105, 100 MMBTUH), DHTU Helper Heater (50 MMBTUH), NHDS Helper Heater (10 MMBTUH), CCR Helper Heater (25 MMBTUH), the FCCU Charge Heater (165 MMBTUH), and the CDU Heater (380 MMBTUH).

Widely accepted petroleum industry references and permit determinations support the basis that refinery gas combustion PM is mainly in the $PM_{2.5}$ size range. Industry research has confirmed this fact. In “$PM_{2.5}$ Speciation Profiles and Emission Factors from Petroleum Industry Gas-Fired Sources.” (Wien, England, et. Al., www.epa.gov/ttnchie1/conference/ei10/poster/wien.pdf), it is stated “The majority of primary emissions from combustion is found in the $PM_{2.5}$ or smaller size range, especially for devices equipped with particulate emissions control equipment and for clean burning fuels such as gas.” The Refinery Emissions Estimation Protocol for Petroleum Refineries (Version 2.1.1, May 2011) Section 4.5 recommends calculating PM emissions from refinery gas combustion using EPA AP-42 Section 1.4 emission factors developed for natural gas combustion in boilers and heaters. The condensable PM fraction from Table 1.4-2, assumed to be $PM_{2.5}$, is 75%. The California Air Resources Board, in PM speciation profiles used for emission inventories (www.arb.ca.gov/ei/speciate/speciate.htm#filelist), cites the fraction of PM emissions less than 2 micron from refinery process heaters as 93%. As a worst-case assumption, all PM_{10} is assumed to be $PM_{2.5}$.

Step 1. Identify All Available Control Technologies

The following is a list of control technologies, which were identified for controlling PM_{10} / $PM_{2.5}$ emissions:

- Good combustion practices;
- Use of low sulfur gaseous fuels;
- Proper design and operation;
- Wet gas scrubber;
- Electrostatic precipitator (ESP);
- Cyclone; and
- Baghouse / fabric filters.

By maintaining the heaters in good working order per manufacturer specifications with low sulfur gaseous fuels, emissions of PM_{10} / $PM_{2.5}$ are reduced.

A wet gas scrubber is an air pollution control device that removes PM and acid gases from waste streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers have some advantages over ESPs and baghouses in that they are particularly useful in removing PM with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM in the presence of soluble gases; and
- PM in gas stream with high moisture content.

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by the charging of particles in the gas stream using positively or negatively charged electrodes. The particles are then collected, as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. Some precipitators remove the particles by washing with water. ESPs are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP.

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles proceed downward, the heavier material hits the outside wall and drops to the bottom where it is collected. The cleaned gas escapes through an inner tube. Cyclones are generally used to reduce dust loading and collect large particles.

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium and low gas flow streams with high particulate concentrations.

Step 2. Eliminate Technically Infeasible Control Options

None of the add-on control devices were identified as being suitable for the process heaters burning gaseous fuels due to both the extremely low concentration of small particulates expected in gas streams from this type of equipment. PM_{10} / $PM_{2.5}$ concentrations in the refinery fuel and natural gas-fired boilers and heaters are even less than the concentrations guaranteed by the cyclones, ESPs, fabric filters, and wet scrubbers. Therefore, wet scrubbers, ESPs, cyclones, and fabric filtration (baghouses) were rejected as BACT for PM_{10} / $PM_{2.5}$ emissions from heaters and boilers.

Step 3. Rank Remaining Control Options
The remaining control option is the utilization of good combustion practices.

Step 4. Evaluate Remaining Control Options
The concept of applying combustion controls and appropriate furnace design or "proper combustion" to minimize PM_{10} / $PM_{2.5}$ emissions include adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. Optimization of these factors for PM_{10} / $PM_{2.5}$ control can result in an increase in the NOx emissions. Heater and boiler designers strive to balance the factors under their control to achieve the lowest possible emissions of all pollutants. Thus, the only control technology identified in the RBLC database for the refinery fuel or natural gas-fired process heaters is a work practice requirement to adhere to good combustion practices and use of low sulfur gaseous fuel. This control strategy is technically feasible and will not cause any adverse energy, environmental, or economic impacts.

Step 5. Select BACT
A review of the RBLC as well as other databases indicated that the most stringent control technologies for PM_{10} / $PM_{2.5}$ are good combustion practices and use of gaseous fuel. Based upon review of the database, the selected PM_{10} / $PM_{2.5}$ BACT emission limit for the proposed new / modified process heaters is selected as 0.0075 lb/MMBTU PM_{10} / $PM_{2.5}$, utilizing proper equipment design and operation, good combustion practices, and gaseous fuels. The heaters undergoing BACT review are: Naphtha Splitter Reboiler (10-105, 100 MMBTUH), DHTU Helper Heater (50 MMBTUH), NHDS Helper Heater (10 MMBTUH), CCR Helper Heater (25 MMBTUH), the FCCU Charge Heater (165 MMBTUH), and the CDU Heater (380 MMBTUH).

4. BACT for New / Modified Process Heaters for Greenhouse Gases

The heaters undergoing BACT review are: Naphtha Splitter Reboiler (10-105, 100 MMBTUH), DHTU Helper Heater (50 MMBTUH), NHDS Helper Heater (10 MMBTUH), CCR Helper Heater (25 MMBTUH), the FCCU Charge Heater (165 MMBTUH), and the CDU Heater (380 MMBTUH). Greenhouse gas (GHG) emissions from process heaters include primarily carbon dioxide (CO_2) with lesser amounts of nitrous oxide (N_2O) and methane (CH_4). The majority of the total GHG emissions, expressed as CO_2e are CO_2 emissions. CO_2 is a product of combustion of fuel containing carbon, such as refinery fuel gas and natural gas. Refinery fuel gas is a mixture of light C1 to C4 hydrocarbons, hydrogen, hydrogen sulfide (H_2S), and other gases.

A search of EPA's RBLC shows no BACT determinations for gas-fired heaters smaller than 100 MMBTUH.

Step 1. Identify All Available Control Technologies
Control technologies identified for reducing GHG emissions from process heaters include:

- Energy-efficient design and good combustion practices;
- Use of low-carbon fuel;
- Carbon capture and sequestration (CCS).

Post-combustion capture systems use chemical or physical absorption/adsorption processes, which may include solvent scrubbing, high temperature sorbents, ionic liquids, biological capture using algae ponds, and membrane technology.

Step 2. Eliminate Technically Infeasible Control Options
The identified control options of energy efficient design and combustion practices and low-carbon fuels are technically feasible and will be reviewed further. The purpose of carbon capture and sequestration (CCS) is to produce a concentrated stream that can be readily transported to a CO_2 storage site. Options to capture CO_2 emissions include oxy-combustion and post-combustion methods. If either carbon capture technology can be utilized, after capture, a compression system to compress the CO_2 is needed to prepare the CO_2 for transport to a permanent geological storage site such as oil and gas reserves and underground saline formations, and to inject the captured CO_2 into the storage site. In oxy-combustion carbon capture, nearly pure oxygen is used for combustion instead of air which results in an exhaust gas that is comprised of mainly H_2O and concentrated CO_2. The process uses an air separation unit to remove the nitrogen component from the air. The oxygen-rich stream is fed to the combustion unit so the resulting exhaust gas contains a concentration of CO_2 of 80% or higher. This technology is still in the research stage.

In addition to oxy-combustion carbon capture, post-combustion capture systems are currently under commercial development. Post-combustion capture is an “end of pipe” technology that involves separating CO_2 from flue gas consisting mainly of nitrogen, water, CO_2 and other impurities.

Carbon capture technologies are not yet commercially available, and appropriate geologic formations have not been proven for long-term underground storage in the vicinity of Tulsa, OK. It is unlikely that there are existing pipelines running through metropolitan Tulsa available for transporting the CO_2. In addition, collateral environmental impacts that could result from sequestration have not been evaluated and require further study. Therefore, carbon capture and sequestration is not considered to be a demonstrated control option at this time, and is therefore eliminated from further consideration in this analysis. In addition, since CCS is not yet commercially available, it is not possible to accurately estimate control costs.

The nearest CO_2 injection location was researched for determining feasibility of CO_2 injection. The applicant looked up current CO_2 injection projects at http://www.natcarbviewer.com sponsored by US Dept of Energy. There is a CO_2 injection study in the development phase about 500 miles to the west in Texas (Chapparal Energy's Farnsworth Unit EOR Field Project), and a small scale injection project sponsored by the University of Kansas about 150 miles to the northwest in the Wellington Field near Wichita, Kansas. Since these injection sites are not commercially available and would require the construction of a lengthy pipeline, they are not considered feasible at this time.

Step 3. Rank Remaining Control Options

The use of energy efficient design and combustion practices and low-carbon fuels to reduce GHG emissions from the proposed new and modified process heaters at HFTR will be standard for the proposed project.

Step 4. Evaluate Remaining Control Options

Possible GHG reduction measures and good combustion practices for new process heaters fired on refinery fuel gas include:

- Draft controls can be installed to limit excess air to an optimal level to reduce energy usage of the burners. Regular maintenance of the draft air intake systems can reduce energy usage;
- Air preheating – the flue gases of the furnace can be used to preheat the combustion air and increase the thermal efficiency of the furnace;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation; and
- Instrumentation to monitor and control excess oxygen levels in the optimal zone to complete combustion while maximizing thermal efficiency.

To the extent that combustion control and good practices increase fuel efficiency, they are an effective means for reducing CO_2 emissions. Preheating the combustion air reduces the amount of fuel required and ultimately lowers GHG emissions since less fuel is being combusted. Maximizing combustion efficiency through process heater burner design and operation further reduces CH_4 emissions and reduces operating cost.

<u>Low-Carbon Fuel</u>

Gaseous fuels such as refinery fuel gas and natural gas reduce CO_2 emissions from combustion relative to burning solid or liquid fuels such as coal or distillate oils. HFTR will primarily use refinery fuel gas in the new process heaters.

Step 5. Select BACT

The BACT selection for GHG emissions from new and modified process heaters (Naphtha Splitter Reboiler, DHTU Helper Heater, NHDS Heater, CCR Helper Heater, and CDU Heater) is good combustion practices, use of low-carbon fuel, and energy efficient design. This includes good air/fuel mixing in the combustion zone, good burner maintenance and operation, sufficient residence time to complete combustion, high temperatures and low oxygen levels in the primary combustion zone, proper fuel gas supply system design and operation, and excess oxygen levels high enough to complete combustion while maximizing thermal efficiency. Oxygen monitors and intake airflow monitors will be used to optimize the fuel/air mixture and limit excess air. As available from the manufacturer, air preheater packages will be installed, consisting of a compact air-to-air heat exchanger installed at grade level through which the hot stack gases from the convection section exchange heat with the incoming combustion air.

For a CO_2e BACT emission limitation for new / modified process heaters, HFTR proposes the value be established in terms of lb CO_2/MMBTU, based upon the manufacturer heat input rating and a default refinery gas CO_2 factor emission factor. BACT is selected as a limit of 146 lb CO_2e/MMBTU to include a safety margin for variations in fuel carbon content.

B. FCCU Regenerator

1. NOx BACT Review

The replacement FCCU regenerator will be a full-burn unit, which is recognized by EPA as an inherently low NO_X design. The predominant NO_X species inside an FCCU regenerator is NO that is further oxidized to NO_2 upon release to the atmosphere. NO_X in the regenerator can be formed by two mechanisms, thermal NO_X produced from the reaction of molecular nitrogen with oxygen, and fuel NO_X, which is produced from the oxidation of nitrogen-containing coke species deposited on the catalyst inside the reactor.

Step 1. Identify All Available Control Technologies

The following is a list of control technologies that were identified for controlling NO_X emissions from a modified FCCU:

- Selective Catalytic Reduction (SCR);
- Selective Non-Catalytic Reduction (SNCR);
- NO_x Oxidation, LoTOX™; and
- Catalyst additives and low NO_X combustion promoters.

Selective catalytic reduction (SCR) is a post-combustion control technology that injects ammonia in flue gas in the presence of a catalyst (typically vanadium or tungsten oxides) to produce N_2 and H_2O. An SCR is similar to SNCR with the exception that a catalyst is used to accelerate the reactions at lower temperatures. The ideal temperature range for an SCR is 600°F to 750°F with guaranteed NOx removal rates of 90+%. Design considerations include targeted NOx removal level, service life, pressure drop limitation, ammonia slip, space limitation, flue gas temperature, composition, and SO_2 oxidation limit. SCR suppliers typically guarantee the performance of the unit for NO_x removal, service life, pressure drop, ammonia slip, and SO_2 oxidation.

An SCR unit has already been installed to meet the requirement of NO_X of 20 ppmvd @ 0% O_2, 365-day rolling average, and 40 ppmvd @0% O_2, 7-day rolling average. Compliance was achieved by January 7, 2010.

The SNCR system is a post-combustion control technology that reacts with urea or ammonia with flue gas without the presence of a catalyst to produce N_2 and H_2O. The typical operating temperature range for an SNCR is 1,600°F to 2,000°F. The SNCR temperature range is sensitive as the reagents can produce additional NO_x if the temperature is too high or removes too little NO_x if the reaction proceeds slowly if the temperature is too low. SNCR has been used successfully with CO boilers, but are typically not used with full burn units due to low NO_x removal at temperatures below 1,400°F. In full burn units, such is utilized by HFTR, the flue gas must be heated to 1,600 to 1,800°F to achieve NO_x removal rates of 50% and greater.

The Belco LoTOx™ technology is a selective, low temperature technology that uses ozone to oxidize NO_X to water-soluble nitric pentoxide (N_2O_5). These higher oxides of nitrogen are highly soluble. Inside a wet gas scrubber, the N_2O_5 forms nitric acid that is subsequently scrubbed by the scrubber nozzles and neutralized by the scrubber's alkali reagent. Since the process is applied at a controlled temperature zone in the wet gas scrubber, it can be used at any flue gas temperature. The controlled temperature zone in the wet gas scrubber is below 300°F. Since the LoTOx™ technology does not use a fixed catalyst bed, it can handle unit upsets without impacting overall reliability and mechanical availability. The LoTOx™ technology generates ozone on demand based on the amount of NO_X in the flue gas. There is no storage of ozone required. Emission reductions using this process have been estimated to range from 80 to 90%.

Several vendors offer NO_X reducing catalyst additives and combustion promoters. Current NO_X additives affect the availability of nitrogen species to be oxidized and reduced and the performance of the additives is dependent on the application. Grace Davison's XNO_X is a combustion promoter additive that can reduce NO_X emission from 50-75% in the regenerator. Grace Davison's DENOX promoter can reduce NO_X emissions up to 60%. Engelhard's CLEANNOX™ and OxyClean™ reduce NO_X emissions by 45%. INTERCAT's COP-NP can reduce emissions from approximately 40-65%. The NO_X combustion promoters (catalysts and additives) are added directly into the FCCU reactor and regenerator. These additives can withstand the harsh environment of the regenerator, but do not have the same life as catalyst.

A benefit associated with the use of additives is flexibility. Additives can be added and removed from the operation depending on the refiner's needs, but are more expensive than FCC catalysts with an average cost approaching $20 per pound. The additional cost associated with the recommended usage rate of these additives may triple the current catalyst cost resulting in negative process unit economics. Higher removal rates may require more additive and that can impact yields, product quality and unit throughput.

Step 2. Eliminate Technically Infeasible Control Options

SNCR is not feasible in this application because of the need to heat the flue gas to reach the optimum operating levels of the SNCR. The amount of NO_X reduction is also lower. Most EPA Consent Decree-related applications have achieved a 5 to 30% reduction with others in the industry achieving up to 70% depending on process conditions (Advances in Fluid Catalytic Cracking, Chapter 17, FCC NO_X Emissions and Controls, Jeffrey A. Sexton, 2010). A drawback of using SNCR technology is the potential formation of ammonium sulfate salts and resultant fouling. These salts will exist as small particulates. SNCR also does not provide the level of emissions control with the SCR unit already installed. Therefore, SNCR is eliminated from consideration. The remaining options are technically feasible.

Step 3. Rank Remaining Control Options

The remaining control options were ranked in order of their reduction potential:

- Selective Catalytic Reduction (SCR) – 90% reduction;
- LoTOx™ - 80- 90% reduction (comparable to SCR); and
- Catalyst additives and low NO_X combustion promoters – 40-75% reduction.

Step 4. Evaluate Remaining Control Options

As stated previously, an SCR unit is already installed on the FCCU. A review of recent CEMS data shows that NOx emissions are consistently reduced to well below the lowest permit limit, 20 ppmvd @ 0% O_2, 365-day rolling average.

LoTOx™ in conjunction with wet scrubbing systems has been demonstrated to effectively reduce high levels of NO_X from an FCCU. The efficiency obtained from the combination of LoTOx™ and wet gas scrubbing systems is comparable to an SCR. Based upon HFTR's experience with LoTOx™ at other refineries, the cost to remove the current SCR and add LoTOx™ will be greater than $1 million, without providing any expected gains in NO_X emissions reduction.

Catalyst additives and combustion promoters alone will not reduce NO_X emissions to meet NO_X BACT levels.

Step 5. Select BACT

A select listing of RBLC entries for FCCU NO_X emissions is provided in the following table. A review of literature and the EPA's RBLC indicate that SCRs, and LoTOx™ in conjunction with wet scrubbing systems, are used for the reduction of NO_X in a number of FCCUs. With an SCR unit already installed by HFTR, and the fact that removing the SCR unit and replacing it with LoTOx™ control is not expected to provide greater emissions control than SCR and will also not be cost-effective, proposed BACT is to retain the current SCR controls and permitted NO_X emission limits of 20 ppmvd @ 0% O_2, 365-day rolling average, and 40 ppmvd @0% O_2, 7-day rolling average.

BACT Determinations for NO_X for an FCCU

FACILITY	RBLC #	PERMIT #	PERMIT DATE	NAME	LIMIT	TECHNOLOGY
HRMT Woods Cross Refinery, UT	N/A	BACT Analysis (within Notice of Intent document)—for Unit 25	January 2019	FCCU	20 ppm (365-day rolling) 40 ppm (7-day rolling)	LoTOx™
	N/A	BACM Analyses (stand-alone)—for Units 4 and 24	April 2017	FCCU	40 ppm (365-day rolling) 80 ppm (7-day rolling)	LoTOx™
Coffeyville Resources Refining & Marketing, LLC, Coffeyville Refinery, KS	N/A	Construction Permit Application for FCCU Optimization Project	October 2018	FCCU	20 ppm (365-day rolling) 40 ppm (7-day rolling) (PROPOSED, as specified in Consent Decree)	Catalyst Additives and SCR
Lion Oil Company. El Dorado, AR	N/A	0868-AOP-R13	4/20/17	Fluid Catalytic Cracking Unit (FCCU), SN-809	40 ppm (7-day rolling) 20 ppm (365-day rolling)	LoTOx™
Tesoro (now Marathon), Salt Lake City, UT	N/A	Consent Decree Case 5:16-cv-00722	7/18/19	FCCU	20 ppm (7-day rolling) 10 ppm (365-day rolling)	LoTOx™

FACILITY	RBLC #	PERMIT #	PERMIT DATE	NAME	LIMIT	TECHNOLOGY
Krotz Springs Refinery	LA-0261	PSD-LA-745(M-2)	4/26/12	Fluid Catalytic Cracking Unit (FCCU) (1-85, EQT 0071)	146 ppm (7-day rolling) 73 ppm (365-day rolling)	LoTOx™
Citgo Corpus Christi East Plant	TX-0562	9604A/PSD-TX-653M1	7/9/10	No. 2 FCCU	180 ppm (1-hr) 20 ppm (365-day rolling)	N/A
Valero Delaware City	DE-0020	AQM-003/00016	2/26/10	Fluid Catalytic Cracking Unit (FCCU)	40 ppm (7-day rolling) 20 ppm (365-day rolling)	LoTOx™
Valero St Charles	LA-0213	PSD-LA-619(M5)	11/17/09	FCCU Regenerator (16-77)	NA	No Controls Feasible
Sunoco Toledo	OH-0308	04-01447	2/23/09	Fluid Catalytic Cracking Unit	40 ppm (7-day rolling) OR 20 ppm (365-day rolling)	SCR
Shell Oil Deer Park	TX-0290	21262/PSD-TX-928	9/27/07	Fluidized-Bed Catalytic Cracking Unit (FCCU)	40 ppm (3-hr rolling) 20 ppm (365-day rolling)	SCR
ExxonMobil Torrance	CA-1138	458743	3/23/07	Fluidized-Bed Catalytic Cracking Unit (FCCU)	40 ppm (7-day rolling) 20 ppm (365-day rolling)	SCR

FACILITY	RBLC #	PERMIT #	PERMIT DATE	NAME	LIMIT	TECHNOLOGY
Marathon Garyville	LA-0211	PSD-LA-719	12/27/06	FCCU regenerator vent (86-74)	40 ppm	Catalyst Additives
Conoco Phillips Ferndale	WA-0324	PSD-00-02 AMENDMENT 3	6/15/05	FCC & CO Boiler	127 ppm	SNCR

N/A = Not listed or currently not available.

2. BACT for CO Emissions from the Modified FCCU

CO emissions will be present in the FCCU regenerator flue gas as a by-product of incomplete coke combustion. CO emissions are currently controlled by monitoring oxygen levels for complete combustion. It is expected that the installation of a new regenerator and FCCU modifications that increase combustion efficiency should likely reduce CO emissions per lb coke burned. The FCCU will be run in full-burn mode.

Step 1. Identify All Available Control Technologies

Four control technologies were identified as potentially able to control CO emissions from a full-burn FCCU regenerator. These technologies are:

- Thermal oxidation;
- Catalytic oxidation;
- CO combustion promoters; and
- Full burn combustion / good combustion practices.

Thermal oxidation uses time, temperature, and turbulence in order to achieve complete combustion. The most common type of thermal oxidizer currently used is a CO boiler. A CO boiler is used to control CO emissions from a partial-burn FCCU regenerator. Partial-burn FCC regenerators operate at or below 1,250ºF. The CO boiler operates at about 1,800ºF to assist with complete conversion of CO and VOC to CO_2. Refineries operating FCCUs exclusively in full-burn combustion mode do not require a CO boiler because effluent CO concentrations are already less than 500 ppmvd.

Catalytic oxidizers, a post-emission control technology, are designed so that the waste gases pass through a flame area and then through a catalyst bed where CO is oxidized to CO_2 at temperatures of 650 to 1,100°F.

CO combustion promoters are additives to the coke combustion process in the regenerator that hampers the formation of NO_x, while enhancing the combustion of coke on the catalyst. The CO combustion promoters are readily fluidized, mixing with the catalyst. They are added to the circulating fluid bed (CFB) regenerator unit to improve the efficiency of CO burning, reduce emissions of CO and improve the efficiency of the unit. The CO combustion promoter accumulates in, or just above, in the fluidized bed combustion zone of the regenerator. There are several CO promoters that are available for use including Engelhard Corporations OxyClean™, Intercat, and Grace Davison's XNO_X, all of which are effective in reducing CO emissions while also controlling NO_X emissions.

Full-burn regenerators operate with excess oxygen in the flue gas, typically 1-3 volume percent on a dry basis. The minimum excess oxygen required to promote complete CO oxidation is a function of bed temperature, gas residence time in the bed, and how efficiently the regenerator design utilizes the available oxygen. If the full-burn unit is properly designed and operated, with sufficient oxygen present, the oxidation of CO to CO_2 should be complete. Therefore, good combustion design and operation will effectively control CO emissions present in the FCCU regenerator exhaust gas.

HFRT is currently required to meet and achieve 500 ppmv @ 0% O_2, 1-hour average. HFTR meets this limit using good combustion practices with CO combustion promoters, and continuously monitoring process parameters and emissions.

Step 2. Eliminate Technically Infeasible Control Options

Thermal oxidation requires use of a CO boiler and operation of the FCCU in partial burn mode. The replacement regenerator will operate in full-burn mode. A CO boiler is not needed, and would not achieve significant additional CO emissions reduction. Therefore, this technology is considered to be technically infeasible.

The regenerator flue gas will exit the WGS at approximately 150°F. The process of reheating the flue gas would result in increased CO. In addition, catalytic oxidation cannot be used on waste gas streams that contain particulate due to the potential for fouling the catalyst, which prohibits oxidation. Thus, catalytic oxidizers are technically infeasible and are eliminated from further consideration.

CO combustion promoters and full-burn / good combustion practices are technically feasible and will be considered further.

Step 3. Rank Remaining Control Options

The remaining control options were ranked in order of their reduction potential:

- CO combustion promoters – 40 to 55% reduction; and
- Full-burn / good combustion practices – baseline control inherent in modified FCCU design.

Step 4. Evaluate Remaining Control Options

The baseline control inherent in the modified FCCU design is full-burn / good combustion practices, to minimize CO emissions generation. In addition, the use of CO promoters as needed to meet current permit limits is technically feasible and cost-effective.

Step 5. Select BACT

A select listing of RBLC entries for FCCU CO emissions is provided in the following table. Good combustion practices and CO combustion promoters will be used by HFTR to minimize CO emissions from the modified FCCU. Using these control options, there are no anticipated additional environmental or energy impacts associated with this unit. Thus, the FCCU in full-burn mode, with the use of CO combustion promoters and good combustion practices are considered BACT for CO. From review of RBLC BACT determinations and recent PSD permit applications, the proposed BACT is to limit CO emissions per the current permit condition required of 500 ppmvd at 0% O_2, one-hour average basis.

BACT Determinations for CO for an FCCU

FACILITY	RBLC #	PERMIT #	PERMIT DATE	NAME	LIMIT	TECHNOLOGY
HRMT Woods Cross Refinery, UT	N/A	BACT Analysis (within Notice of Intent document)—for Unit 25	January 2019	FCCU	500 ppmvd (1-hr avg.)	Full-burn and CO promoter
Coffeyville Resources Refining & Marketing, LLC, Coffeyville Refinery, KS	N/A	Construction Permit Application for FCCU Optimization Project	October 2018	FCCU	500 ppm (PROPOSED)	Continued use of full-burn operations
Lion Oil Company, El Dorado, AR	N/A	0868-AOP-R13	4/20/17	#7 Fluid Catalytic Cracking Unit (FCCU), SN-809	500 ppm (1-hr); 100 ppm (365-day rolling)	High Temperature Regeneration
Tesoro (now Marathon), Salt Lake City, UT	N/A	Consent Decree Case 5:16-cv-00722	7/18/19	FCCU	500 ppm (1-hr); 100 ppm (365-day rolling)	Not stated
Citgo Corpus Christi East Plant	TX-0562	9604A/PSD-TX-653M1	7/9/10	No. 2 FCCU	500 ppm (1-hr) 100 ppm (annual)	Good Combustion Practices
Valero Corpus Christi	TX-0592	38754 AND PSDTX324M13	3/29/10	FCCU	1,200 ppm	Preheat and control torch oil combustion
Valero St Charles	LA-0213	PSD-LA-619 (M5)	11/17/09	FCCU regenerator (16-77)	696.8 lb/hr, 95 TPY	Full-burn Design
Chalmette Refining	LA-0222	PSD-LA-199(M-8)	9/15/09	Fluid Catalytic Cracking Unit (FCCU)	500 ppm (1-hr) 300 ppm (annual)	Full-burn Operation and Good Combustion Practices

FACILITY	RBLC #	PERMIT #	PERMIT DATE	NAME	LIMIT	TECHNOLOGY
Sunoco Toledo	OH-0308	04-01447	2/23/09	Fluidized catalytic cracking unit	500 ppm (1-hr) OR 180 ppm (annual)	CO Boiler
ConocoPhillips Wood River	IL-0103	06050052	8/5/08	Modified Fluidized Catalytic Cracking Units 1 & 2	500 ppm (1-hr) 100 – 150 ppm (annual)	CO Combustion
Lion Oil	AR-0100	868-AOP-R5	10/1/07	#7 FCCU catalyst regenerator, SN-809	500 ppm (1-hr) 100 ppm (annual)	High Temperature Regeneration
Valero Ardmore	OK-0116	98-172-C M-19 PSD	2/8/07	FCCU No. 1 Regenerator and CO Boiler/ Incinerator FCCU No. 2 Regenerator	175 ppm 50 ppm	Thermal Oxidation
Marathon Garyville	LA-0211	PSD-LA-719	12/27/06	FCCU regenerator vent (86-74)	481.76 lb/hr	Full-burn Operation
Sunoco	PA-0250	4322	2/28/06	1232 FCCU	500 ppm (1-hr) 100 ppm (annual)	CO Boiler
Marathon Detroit	MI-0378	28-02A	1/5/06	FCCU Catalyst Regeneration	500 ppm (annual)	Good Combustion Practice

FACILITY	RBLC #	PERMIT #	PERMIT DATE	NAME	LIMIT	TECHNOLOGY
Conoco Phillips Ferndale	WA-0324	PSD-00-02 AMENDMENT 3	6/15/05	FCCU	500 ppm (1-hr) 100 ppm (annual)	Good Combustion Practices
Lion Oil El Dorado	AR-0089	868-AOP-R2	1/3/05	Fluidized bed catalytic cracking unit (FCCU)	5000 ppm (1-hr) 1000 ppm (annual)	Full Combustion

N/A = Not listed or currently not available.

3. BACT for PM_{10} and $PM_{2.5}$ Emissions from the Modified FCCU

For the proposed Refinery Expansion project, with the increase in the modified FCCU charge rate and replacement of the regenerator unit, the maximum coke burn-off rate will increase, which will potentially increase PM emissions. The PM emissions not captured by the existing wet gas scrubber (WGS), resulting from the burning of coke off the catalyst in the FCCU regenerator vessel, are released out of the regenerator stack. The main source of PM is catalyst fines and products of incomplete combustion. The PM emissions include both filterable and condensable PM and may also include trace organic compounds and sulfuric acid mist.

PM consists of two parts, filterable and condensable. Filterable (or front-half) PM is the material that is captured on the filter and in the probe used in the EPA Method 5 test. Condensable (or back-half) PM is particulate that passes through the filter as a gas and is measured using EPA Reference Method 202. PM_{10} is PM less than 10 microns in mean aerodynamic diameter produced by coke burn-off. Similarly, $PM_{2.5}$ is PM less than 2.5 microns in diameter. The filterable fractions of PM_{10} and $PM_{2.5}$ emissions from some types of sources can be measured independently using EPA Reference Method 201A, which uses inertial (cyclonic) separation to eliminate particles larger than the specified size, but Method 201A cannot be used with exhaust streams saturated with water and containing water droplets. Because most of the PM associated with the FCCU coke burn-off is $PM_{2.5}$, and because Method 201A cannot be used, PM_{10} and/or $PM_{2.5}$ are used interchangeably with PM for purposes of this BACT analysis. Therefore, total PM from coke burn-off is the sum of filterable and condensable PM.

Step 1. Identify All Available Control Technologies

The following list of technologies were identified as PM control options for FCCUs based on information obtained from the RBLC database and other sources:

- Wet Gas Scrubber (WGS);
- Baghouse/Fabric Filter;
- Dry Electrostatic Precipitator (ESP);
- Wet Electrostatic Precipitator (WESP); and
- Third Stage Separator (TSS) / Cyclone.

Wet gas scrubbing is an air pollution control technology that removes PM and acid gases from waste gas streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception, and/or absorption of the pollutant onto droplets of liquid.

WGSs have some advantages over dry ESPs and baghouses in that they are particularly useful in removing PM with the following characteristics:

- Sticky and/or hygroscopic materials;
- Combustible, corrosive or explosive materials;
- Particles that are difficult to remove in dry form;
- PM in the presence of soluble gases; and
- PM in gas stream with high moisture content.

A WGS unit was previously installed at the HFTR East Refinery (previously the Sinclair Tulsa Refinery) FCCU to meet the emission limit of 1 pound PM per 1,000 pounds coke, 3-hour average, based upon Method 5 for filterable PM. The Specific Condition in HFTR's permit for EUG-11 includes these requirements; compliance was required by June 30, 2008. The existing WGS was required by EPA under the Consent Decree to be designed and installed as capable to meet the Consent Decree-optional PSD emission limit of 0.5 lb PM / 1,000 lb coke, as filterable PM. While no limits were established under the Consent Decree, the WGS also controls filterable $PM_{2.5}$ as well as condensable PM_{10} / $PM_{2.5}$.

A fabric filter unit (or baghouse) consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter. Fabric filters are used for medium- and low-flow rate gas streams with high particulate concentrations.

An ESP is a particulate control device that uses electrical forces to move the particles out of the gas stream onto collector plates. This process is accomplished by charging particles in the gas stream using either positively- or negatively-charged electrodes. The particles are then collected, as they are attracted to oppositely opposed electrodes. Once the particles are collected on the plates, they are removed by knocking them loose from the plates, allowing the collected layer of particles to fall down into a hopper. Some precipitators remove the particles by washing with water. ESP's are used to capture coarse particles at high concentrations. Small particles at low concentrations are not effectively collected by an ESP.

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles proceed downward, the heavier material hits the outside wall and drops to the bottom where it is collected. The cleaned gas escapes through an inner tube. Cyclones are generally used to reduce dust loading and collect large particles.

A third stage separator (TSS) is a specially designed cyclone or set of cyclones, for the flue gas from an FCCU regenerator. The TSS is in a separate vessel, outside the regenerator, that houses a number of small-diameter, high efficiency cyclones arranged in parallel in the vessel. There is a flow distributor at the inlet to evenly distribute the regenerator flue gas to each small cyclone to create better efficiencies in particulate removal. The TSS would remove a significant amount of particulate that would normally exhaust via the regenerator stack.

Step 2. Eliminate Technically Infeasible Control Options

Each of the technologies, except the baghouse/fabric filter, is considered technically feasible. The baghouse is considered technically infeasible for several reasons. Construction of readily available fabric filters is not typically able to withstand gas streams greater than approximately 500 ^{o}F, whereas the normal exit gas temperature from the FCCU regenerator stack into the WGS is expected to be greater than approximately 600 ^{o}F, although there are some commercially available ceramic fabrics that can handle higher temperatures. Secondly, moisture is a significant problem, as it can cause “blinding” of the fabric bags; as the WGS is already in place, it is not anticipated that a baghouse could be placed downstream of it. Therefore, a baghouse is removed from further consideration as technically infeasible for FCCU PM emissions control.

Step 3. Rank Remaining Control Options

The following lists the ranking of the remaining control options in general order of expected effectiveness from high to low:

- Wet Gas Scrubber;
- Electrostatic Precipitators; and
- Third Stage Separator.

Step 4. Evaluate Remaining Control Options

Electrostatic precipitation is a proven technology. The collected particulate is disposed of as a dry solid. The discharge stream does not have a vapor plume. There is a small pressure drop across the electrostatic precipitator (ESP). The particle collection process begins when the particle absorbs a charge sufficient amount to be attracted to the collection plates. However, the particle charging and collection process can be affected by several factors including particle size, particle resistivity, electric field and the temperature and composition of the flue gas stream. A few examples of ESPs installed on FCCUs have been identified, including: CHS Inc. Laurel Refinery, Laurel, Montana; Marathon Petroleum, Detroit, Michigan; Phillips 66 Sweeny Refinery, Old Ocean, Texas; and Citgo Refinery East Plant, Corpus Christi, Texas. In these cases, they were required under EPA Consent Decree and/or addressed technical limitations with other options such as WGS.

There can be reliability issues with ESPs; in many cases, multiple units must be installed for redundancy to achieve the required level of control, which adds significant costs. Temperature and humidity affect the resistivity of PM. An ESP has a limited ability to handle high temperature excursions or FCCU upsets. In addition, any VOCs that might be in the stream because of an upset are dangerous to the unit. ESPs are also susceptible to changes in catalysts.

TSS removes a significant amount of catalyst fines from the flue gas stream. However, a TSS by itself will not reduce particulate to meet the level that can already be achieved with the existing WGS. Use of a TSS alone on existing FCCUs was not identified in an RLBC search. Such technology could be expected to be used in conjunction with other technologies such as ESP.

The WGS is a proven technology extensively used on FCCU units. The technology has been demonstrated to remove both particulate matter and SO_2 to low levels on a long-term basis. A WGS has excellent reliability; therefore, there is no need for multiple units (as with ESP). Wet scrubbers have a much broader operating range and are more adept at handling upsets from an FCCU. A WGS results in a lower operating temperature than an ESP, which provides for improved removal of condensable PM. The waste from a WGS can be disposed of as a wet solid. Therefore, the WGS is preferred and more cost-effective than the other PM control options. The existing WGS is designed to achieve 0.5 lb filterable PM / 1,000 lb coke burn. From source test data, the WGS has met that level, and also achieved total PM emissions less than 1 lb / 1,000 lb coke burn. Replacing the existing WGS with a new WGS would not be expected to further reduce PM emissions, and such replacement would not be cost-effective.

Step 5. Select BACT

A listing of recent air permits and RBLC entries for modified FCCU PM emissions is provided in the following table. WGSs are used extensively as the primary method to reduce PM emissions from FCCUs. For WGSs, the RBLC has a range of BACT determinations from 0.5 to 1.0 lb filterable PM /1,000 lb coke burn, with 0.5 lb PM / 1,000 lb coke burn a typical BACT value, and 0.6 to 2 lb total PM (filterable and condensable) / 1,000 lb coke burn.

Based upon review of HFTR East Refinery PM source test data from the years 2016 - 2018, the existing WGS has achieved the current compliance limit of 1 lb filterable PM per 1,000 lb coke burn. The facility test results for total PM (filterable and condensable) have consistently measured below 1 lb / 1,000 lb coke burn. While individual 3-hour test runs have measured total PM at less than 0.6 lb /1,000 lb coke burn, other tests have measured higher, and the WGS at the HFTR FCCU has not demonstrated that these lower total PM levels are achievable with an adequate assurance of compliance.

PSD BACT applies to total PM, not only the filterable portion. HFTR does not consider the limits for filterable PM, or the limits for non-sulfate filterable PM as determined using EPA Reference Methods 5B or 5F, to satisfy the requirements for BACT for total PM under DEQ’s PSD regulations. While the available RBLC determinations and recent permit documents reviewed suggest that the achievable limits for total PM from a modified FCCU may in some instances be as low as 0.6 lb PM / 1,000 lb coke burn, the WGS at HFTR has demonstrated only that 1 lb total PM per 1,000 coke burn can be consistently achieved, including a sufficient margin for source test variability.

For the modified FCCU, HFTR proposes to reduce PM emissions using the existing WGS. HFTR proposes a BACT emission limit of 1 lb PM / 1,000 lb coke burn, 3-hour average, average of three test runs, based upon EPA Method 5 and Method 202.

BACT Determinations for PM for an FCCU

FACILITY	RBLC #	PERMIT #	PERMIT DATE	NAME	LIMIT (LB/1000 LB COKE)	TECHNOLOGY
HRMT Woods Cross Refinery, UT	N/A	BACT Analysis (within Notice of Intent document)	January 2019	FCCU	0.6 (total PM_{10} limit for 25FCC, PROPOSED in both pending construction permit app and BACT in NOI dated January 2019) [1]	Wet gas scrubber
	N/A	BACM Analyses (stand-alone)	April 2017	FCCU	0.3 (PM_{10}—$PM_{2.5}$ controlled via WGS 25FCC-Unit 25) [1] 0.5 (PM_{10}—$PM_{2.5}$ controlled via WGS	Wet gas scrubber
Coffeyville Resources Refining & Marketing, LLC, Coffeyville	N/A	Construction Permit Application for FCCU Optimization Project	October 2018	FCCU	0.5 (PM filterable, 3-hour average, consistent with Consent Decree) (PROPOSED)	ESP and Cyclones
Phillips 66 Ferndale. Washington	N/A	016R2	1/1/18	Fluid Catalytic Cracking Unit (FCCU)	0.5 (filterable PM; 3-run, 365-day rolling average)	Wet gas scrubber
Lion Oil Company. El Dorado, AR	N/A	0868-AOP-R13	4/20/17	Fluid Catalytic Cracking Unit (FCCU), SN-809	0.5 (filterable PM, 3-hour average) 1.0 (total PM_{10}, 3-hour average)	Wet gas scrubber

FACILITY	RBLC #	PERMIT #	PERMIT DATE	NAME	LIMIT (LB/1000 LB COKE)	TECHNOLOGY
	AR-0119	0868-AOP-R9	9/9/11	Fluid Catalytic Cracking Unit (FCCU), SN-809	1 (filterable PM_{10})	Wet gas scrubber
Marathon Detroit, Michigan	N/A	MI-ROP-A9831-2012c	9/12/16	Fluid Catalytic Cracking Unit (EU11-FCCU-S1)	0.8 (total PM, 3-hour rolling average); and 1.1 (PM_{10}, 3-hour rolling average)	Regenerator cyclones and Electrostatic precipitators
BP Whiting Refinery, Indiana	N/A	089-35729-00453	9/16/15	Fluidized Catalytic Cracking Units (FCU) 500 and 600	FCU 500: 0.9 (total PM_{10}); and 1.2 (total PM); FCU 600: 0.7 (total PM_{10}); and 1.2 (total PM)	ESP
Sweeny Refinery	TX-0587	5920A AND PSDTX103M4	12/29/10	Fluid Catalytic Cracking Unit (FCCU)	1.334 ($PM_{2.5}$)	Regenerator cyclones and Electrostatic Precipitator
Citgo Corpus Christi East Plant	TX-0562	9604A/PSD-TX-653M1	7/9/10	No. 2 FCCU	2.0 (PM)	Electrostatic Precipitator
Lion Oil Company. El Dorado	AR-0100	868-AOP-R5	10/1/07	#7 FCCU catalyst regenerator, SN-809	0.5 (filterable PM; 3-run average, non-sulfate) 1.0 (total PM10)	Wet gas scrubber

FACILITY	RBLC #	PERMIT #	PERMIT DATE	NAME	LIMIT (LB/1000 LB COKE)	TECHNOLOGY
Sun Company, Inc. Toledo Refinery	OH-0308	04-01447	2/23/09	Fluidized catalytic cracking unit	0.9 (filterable PM_{10})	Wet gas scrubber
St. Charles Refinery	LA-0213	PSD-LA-619 (M5)	11/17/09	FCCU regenerator (16-77)	1 (PM_{10})	Wet scrubber
Marathon Petroleum Co., Garyville Refinery	LA-0211	PSD-LA-719	12/27/06	FCCU regenerator vent (86-74)	0.6 (total PM_{10})	Wet gas scrubber
Sunoco, Inc. (R&M) (now Philadelphia Energy Solutions)	PA-0250	4322	2/28/06	1232 FCCU	0.5 (filterable PM; 3-run, 365-day rolling average); 0.3 (filterable PM_{10}, 365-day rolling average)	Wet gas scrubber
Ferndale Refinery	WA-0324	PSD-00-02 AMENDMENT 3	6/17/05	FCCU	0.5 (PM_{10} 3-hour avg.)	Wet gas scrubber
Lion Oil Company, El Dorado	AR-0089	868-AOP-R2	1/3/05	Fluidized bed catalytic cracking unit (FCCU)	0.5 (3-hour average)	Wet gas scrubber

[1] An adjustment of the 0.3 lb per 1000 lb coke in the 2013 AO for 25FCC is being requested based on operating experience and to address the condensable PM_{10} fraction emitted from the FCCU. The 0.3 lb limit had been based solely on the filterable fraction of PM_{10} rather than total, to include condensable PM_{10}. A revised limit covering all forms of particulate matter (filterable and condensable fractions of PM10) of 0.6 lb per 1000 lb coke has been proposed for 25FCC.

4. BACT for GHG Emissions from the Modified FCCU

Greenhouse gas (GHG) emissions from the FCCU include products of coke combustion, as primarily carbon dioxide (CO_2), with trace amounts of nitrous oxide (N_2O) and methane (CH_4) emissions. Total GHG emissions are also expressed as carbon dioxide equivalents (CO_2e). A full-burn FCCU, such as proposed, operates with sufficient air to convert most carbon in coke to CO_2 rather than CO. Any N_2O or CH_4 formed from coke combustion results as products of incomplete combustion.

Step 1. Identify All Available Control Technologies

The requirement to control GHG emissions from petroleum refinery emission sources is relatively new, with a limited history of review for control of GHG emissions from FCCUs. EPA has issued the following guidance documents that were utilized as resources to complete the GHG BACT evaluation for the proposed project:

- *PSD and Title V Permitting Guidance For Greenhouse Gases (2011)* https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf; and
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry (2010)* https://www.epa.gov/sites/production/files/2015-12/documents/refineries.pdf

In determining whether a technology is available for controlling GHG emissions from the modified FCCU, recent permit applications and EPA's RBLC were consulted. Limited information was found; RBLC does not list any determinations as PSD BACT for FCCUs. Based on the EPA guidance resources listed above, the following available control technologies were identified:

- Carbon Capture and Storage (CCS);
- Power/Waste Heat Recovery; and
- High-Efficiency Regenerators.

Carbon capture and storage is the process of producing a concentrated stream that can be readily transported to a CO_2 storage site. Options to capture CO_2 emissions include pre-combustion, oxy-combustion and post-combustion methods. If any of these carbon capture technologies can be utilized, after capture, a compression system to compress the CO_2 is needed to prepare the CO_2 for transport to a permanent geological storage site such as oil and gas reserves and underground saline formations, and to inject the captured CO_2 into the storage site.

Pre-combustion capture refers to removing CO_2 from fossil fuels before combustion is completed. For example, in gasification processes a feedstock is partially oxidized in steam and oxygen/air under high temperature and pressure to form synthesis gas (mixture of mainly hydrogen and CO_2). The CO_2 can then be captured and separated while producing a hydrogen rich fuel to be used for combustion.

In oxy-combustion carbon capture, nearly pure oxygen is used for combustion instead of air which results in an exhaust gas that is comprised of mainly H_2O and concentrated CO_2. The process uses an air separation unit to remove the nitrogen component from the air. The oxygen-rich stream is fed to the combustion unit so the resulting exhaust gas contains a concentration of CO_2 of 80% or higher. This technology is still in the research stage.

In addition to oxy-combustion carbon capture, post-combustion capture systems are currently under commercial development. Post-combustion capture is an "end of pipe" technology that involves separating CO_2 from flue gas consisting mainly of nitrogen, water, CO_2 and other impurities.

The modified FCCU is a possible candidate for power/waste heat recovery, which decreases GHG emitted per lb coke burned. Facilities that have power/waste heat recovery from an FCCU typically employ an additional waste heat boiler and/or a power recovery turbine or turbo expander to recover energy from the FCCU catalyst regenerator exhaust.

High-efficiency regenerators are specially designed to allow complete combustion of coke deposits without the need for a post-combustion device, reducing auxiliary fuel combustion associated with a CO boiler.

Step 2. Eliminate Technically Infeasible Control Options

Carbon capture technologies are not yet commercially available, and appropriate geologic formations for sequestration have not been proven for long-term underground storage in the vicinity of Tulsa, Oklahoma. In addition, collateral environmental impacts that could result from sequestration have not been evaluated and require further study. Therefore, carbon capture and sequestration is not considered to be a technically feasible control option at this time, and is therefore eliminated from further consideration in this analysis. In addition, since CCS is not yet commercially available, it is not possible to accurately estimate control costs.

The nearest CO_2 injection location was researched for determining feasibility of CO_2 injection. HFTR researched the location of current CO_2 injection projects sponsored by US Dept. of Energy via its NATCARB Viewer (https://edx.netl.doe.gov/dataset/natcarb/resource/2596c42e-e48d-4375-84cb-c9ede83fc12e). There is a CO_2 injection study in the development phase about 500 miles to the west in Texas (Chaparral Energy's Farnsworth Unit EOR Field Project); a storage validation test at the Texas SWP SACROC Enhanced Oil Recovery site at about the same distance from Tulsa (approximately 500 miles); and a small scale injection project sponsored by the University of Kansas about 150 miles to the northwest in the Wellington Field near Wichita, Kansas. Since these injection sites are not commercially available and would require the construction of a lengthy pipeline, they are not considered technically feasible at this time.

For the power/waste heat recovery option, the waste heat is expected to be of low quality, that is, with low temperature and heating content. It can be difficult to efficiently utilize the quantity of low quality heat contained in a waste heat medium. Heat exchangers tend to be larger to recover significant quantities which increases capital cost. Since the flue gas stream from the FCCU can be considered low quality, this control technology becomes a technically infeasible option.

High-efficiency regenerators are specially designed to allow complete combustion of coke deposits without the need for a post-combustion device reducing auxiliary fuel combustion associated with a CO boiler. Due to proposal to operate the FCCU at full burn or complete-combustion, this is a redundant option. HFTR will operate a full burn FCCU after the modification without a CO boiler.

Step 3. Rank Remaining Control Options

No remaining GHG emission control options remain to be ranked.

Step 4. Evaluate Remaining Control Options

No remaining GHG emission control options remain to be evaluated.

Step 5. Select BACT

No modified FCCU GHG emissions control options were identified as technically feasible, including CCS, power/waste heat recovery and high-efficiency regenerators.

VII. EVALUATION OF AIR QUALITY IMPACTS AND DETERMINATION OF MONITORING REQUIREMENTS

Introduction

For the minor changes related to this modified PSD construction permit the applicant was required to submit updated Class II area air dispersion modeling analysis for NO_2, PM_{10}, $PM_{2.5}$, and CO. These updated analyses addressed both NAAQS and Increment modeling and related cause or contribute analyses. The updated modeling analyses indicates negligible changes in the modeled impacts and the conclusions of the original PSD construction permit did not change. Because the changes did not result in a significant change in impacts, the Class II visibility analysis and Class I screening analysis were not updated.

Changes related to the modeling since issuance of Permit No. 2012-1062-C (M-1) PSD on April 20, 2015, have been incorporated where applicable and discussion included for historical purposes has also been noted. EPA comments and the AQD responses to EPA comments from the original PSD construction permit are available as part of the original PSD construction permit record. Since issuance of the original PSD construction permit, the construction permit and related modeling analysis was revised in Permit No. 2012-1062-C (M-6) PSD issued on November 12, 2015, and in Permit No. 2012-1062-C (M-13) issued on March 21, 2019. In the modified permit, the NO_2, PM_{10}, $PM_{2.5}$, and CO modeling was updated to incorporate the proposed changes and additional changes to the nearby source inventory.

In June 2017, the AQD Air Dispersion Modeling Guidelines was updated and part of this update was to incorporate a newer (2011-2015) meteorological dataset. The guidance allows for an 18-month transition period when revising previous modeling analyses. However, the meteorological data is required to be processed using the most recent version of AERMET.

On January 17, 2017, EPA published updates to 40 CFR Part 51, Appendix W, *Guideline on Air Quality Models*. Some of the changes to Appendix W were applicable to and affected the revised modeling submittal. The updates to Appendix W became effective on February 16, 2017, and a one year transition period for the updates ended on January 17, 2018. This permit application was administratively complete on July 30, 2019, which is after the applicable transition period for the updates of Appendix W. In June of 2017, the AQD Air Dispersion Modeling Guidelines were updated to incorporate these changes. Where applicable, changes to the modeling analyses related to the updates in Appendix W have been incorporated or addressed.

Model Selection and Description

The original PSD modeling was conducted in accordance with the modeling protocol dated April 22, 2013, and reviewed by AQD, and the subsequent draft *Request to use Tier 3 Plume Volume Molar Ratio Method and/or Ozone Limiting Method for* NO_2 *Modeling* (draft March 12, 2014, updated May 19, 2014) which was also submitted to the EPA. EPA comments and AQD responses to EPA comments concerning the original PSD construction permit modeling are contained in the permit record of the original PSD construction permit. The original PSD construction permit modeling was completed following the *Guideline on Air Quality Models* 40 CFR Part 51, Appendix W dated November 6, 2005, and the AQD *Air Dispersion Modeling Guidelines* dated June 2017, with additional guidance from AQD staff. The updated Class II area air dispersion modeling analysis for NO_2, PM_{10}, $PM_{2.5}$, and CO was completed following the updated *Guideline on Air Quality Models* 40 CFR Part 51, Appendix W dated January 17, 2017, and the AQD *Air Dispersion Modeling Guidelines* dated June 2017.

Criteria pollutant modeling was conducted using Lakes Environmental Software, AERMOD View (Version 9.7.0). This software incorporates the AMS/EPA Regulatory Model (AERMOD) Version 18081, endorsed by EPA. AERMOD is a regulatory steady state plume modeling system. Five years of hourly meteorological data from the ASOS site in Tulsa, Oklahoma at the Richard L. Jones, Jr. Airport (KRVS: 2011–2015) were input into the model. In accordance with AQD modeling guideline Section 1.4.2, the most recent EPA-approved AERMOD Model Version 18081 was used for Class II modeling. The Class I significance modeling at 50 km distance from the original PSD permit was not revised. Other models were used as required to complete the original PSD construction permit modeling analyses. CALPUFF Version 5.2.0 was used for Tier 2 significance modeling from the original PSD construction permit. The VISCREEN visibility model Version 13190 was used for Class II visibility screening in the original PSD construction permit.

Class II Area Dispersion Modeling Approach by Pollutant

Class II area modeling was completed to assess project impacts, including the significance analysis, the PSD NAAQS and increment consumption analyses. This section presents the modeling approach by each pollutant considered.

NO_2 Modeling Approach

A full impact modeling analysis was required for 1-hour and annual average NO_2 emissions. SIL, NAAQS, and increment modeling for the project and nearby sources was completed using Tier 3 methods utilizing OLM group ALL for a combined plume analysis. Background concentration data was added for the NAAQS modeling.

EPA provides NO_2 modeling guidance in two memoranda, *Guidance Concerning the Implementation of the 1-hour NAAQS for the Prevention of Significant Deterioration Program* (EPA 2010a) and *Additional Clarification Regarding the Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (EPA 2011), as well as 40 CFR Part 51 Appendix W (EPA 2017). The guidance lists three refinement Tiers for completing 1-hour NO_2 modeling to obtain design concentrations for the short-term standard, the five-year average of the 98th percentile of the annual distribution of daily maximum 1-hour NO_2 concentrations, and also for the maximum annual average NO_2 concentrations over the numbers of years modeled. Tier 1 assumes full conversion of in-stack nitric oxide (NO) emissions to NO_2. Tier 2 applies a default ambient conversion ratio of 0.90 for NO-to-NO_2 conversion. The Tier 3 method is to further refine the modeling analysis and conversion of in-stack NO to ambient NO_2 using the Plume Volume Molar Ratio Method (PVMRM) or the Ozone Limiting Method (OLM), with five years of hourly background ozone data that are concurrent with the meteorological data set. For Tier 3, an initial in-stack conversion of NO to NO_2 is assumed as a ratio to total NO_X emissions (or an in-stack NO_2/NO_X ratio).

Use of the Tier 3 analysis in the original PSD construction permit modeling required approval from AQD and submittal of a protocol to EPA for approval. Comments received by EPA on the Tier 3 modeling protocol were addressed separately in a final response to EPA and are available in the original PSD construction permit record. Due to the updates of Appendix W, the use of OLM in a Tier 3 analysis is considered a regulatory option.

AQD provided the 98th percentile hourly NO_2 and ozone concentration files for 2011 – 2015, processed on a Seasonal, Hour-of-Day, and Day-of-Week basis from the North Tulsa monitor (40-143-1127). For HFTR sources, the EPA default in-stack NO_2/NO_X ratio of 0.5 was used. For nearby facilities, AQD has provided in-stack ratios for various types of combustion sources. AQD has based the in-stack NO_2/NO_X ratios for engines, and heaters/boilers on test data for similar sources. The source data used to develop these in-stack ratios are part of the EPA NO_2 ISR database available on the EPA SCRAM webpage: https://www.epa.gov/scram/nitrogen-dioxidenitrogen-oxide-stack-ratio-isr-database/.

EPA comments and AQD responses to EPA comments concerning in-stack ratios from the original PSD construction permit are available as part of the permit record of the original PSD construction permit. An in-stack NO_2/NO_X ratio of 0.2 was used for all other nearby sources. Tier 3 modeling was completed using the default equilibrium ratio of 0.9.

In-Stack NO_2/NO_X Ratios for Nearby Sources

Source Type	Ratio
LB Engines	0.35
4SRB Engines	0.05
Boilers	0.10
Other Emission Units	0.20

For NO_2, there is a specific control option in AERMOD referred to as the "EPA NAAQS Option," which was used for modeling NO_2 NAAQS compliance. This option is effective for calculating impacts from 1-hour NO_2 as they relate to EPA regulations. A use of this Method applied to this modeling study is the contribution or "MAXDCONT" output files that display source group contributions to concentration totals at individual receptors, paired in time and space, and allowing a cause and contribute analysis to be performed.

$PM_{2.5}$ Modeling Approach

A full impact modeling analysis was required for 24-hour $PM_{2.5}$ emissions. SIL, NAAQS, and increment modeling for the project and nearby emission sources was completed following EPA and AQD guidance for these pollutants. Background concentration data was added for the NAAQS modeling analysis.

AERMOD has a specific control option in AERMOD referred to as the "$PM_{2.5}$ EPA NAAQS Option," which was used for modeling $PM_{2.5}$ NAAQS compliance. This option is effective for calculating impacts from 24-hour $PM_{2.5}$, as they relate to EPA regulations. A use of this method applied to this modeling study is the contribution or "MAXDCONT" output files that display source group contributions to concentration totals at individual receptors, paired in time and space, and allowing a cause and contribute analysis to be performed. An annual NAAQS or PSD Increment analysis was not required.

The significance emissions rate (SER) for direct $PM_{2.5}$ impact analysis is 10 TPY and the SER for the $PM_{2.5}$ precursors NO_X and/or SO_X are 40 TPY. A $PM_{2.5}$ modeling impact analysis would need to be completed if the NO_X net emission increase exceeds the SER.

As indicated in the original PSD construction permit, as part of their Consent Decree, HFTR West recently completed facility changes with large actual SO_X and NO_X emission reductions. The emission reductions, while mandated for SO_X and NO_X, are contemporaneous and creditable with the proposed project for secondary $PM_{2.5}$ impacts. Actual SO_X emissions will decrease 1,916 tons/year, based upon the difference between reported 2010-2011 SO_X emissions (2,300 tons/year) and the Projected Actual Emissions (PAE) for SO_X (384 tons/year) after project completion. Actual NO_X emissions will increase 722 tons/year, based upon the difference between reported 2010-2011 NO_X emissions (1,036 tons/year) and the Projected Actual Emissions for NO_X (1,758 tons/year) after project completion. Therefore, overall there will be a large net decrease of combined SO_X and NO_X emissions of 1,194 tons/year. Note that standard EPA inter-pollutant trading ratios value SO_X emission reductions at 2-5 times NO_X emission reductions. No further analysis of secondary $PM_{2.5}$ impacts was required in the original PSD construction permit. EPA comments and AQD responses to EPA comments concerning secondary impacts in the original PSD construction permit are available as part of the permit record of the original PSD construction permit.

The minor changes related to the modified construction permit were not significant enough to revise the historical determination related to secondary formation. Also, the permit application for the modified construction permit were received prior to the end of the transition period related to the updates of Appendix W addressing $PM_{2.5}$ secondary formation.

CO and PM_{10} Modeling Approach

For 1-hour and 8-hour average CO and 24-hour and annual average PM_{10} project emissions, only a significance analysis was completed. Full impact modeling was not required because modeled impacts were below the SILs.

<u>Control Parameters</u>

AERMOD was run in the regulatory default mode, including stack-tip downwash and use of elevated terrain algorithms.

The land type in the area must be classified as either urban or rural so that appropriate dispersion parameters may be used with AERMOD. The area within and surrounding the refineries is industrial, and the facility is located in a metropolitan area. To simulate the urban heat island effect, the urban option within AERMOD was selected, assuming the Tulsa population equals 396,466 persons, and with a surface roughness of 1.0 meter.

AERMOD has the capability to account for building downwash produced by airflow over and around structures. Direction-specific building downwash parameters were developed for HFTR sources for input to AERMOD-PRIME using the USEPA Building Profile Input Program, or BPIP-PRIME Model (Version 04274). The BPIP model requires building dimensions as well as stack locations for input. These parameters were determined from site plan maps.

Terrain Considerations

Per AQD guidance, modeling with elevated terrain was conducted. AERMAP (version 18081), was used to assign elevations to stack, buildings, receptors, and hills. Receptor elevations were developed using the National Elevation Dataset (NED) data. The NED data was converted to GeoTIFF format and processed using the Lakes Environmental AERMOD View GUI interface with AERMAP. NED data was processed at 1/3 Arc-Sec resolution; receptor terrain values were interpolated from the nearest NED grid points. Elevations were manually applied to sources and buildings using Google Earth. In the case of where results were sensitive to the elevations at design receptors, interpolated elevations were visually verified using topographical maps and Google Earth, and then refined as needed for accuracy. The base elevation of the facility is approximately 640 feet above mean sea level.

USEPA guidance supports the use of AERSURFACE to process land cover data to determine the surface characteristics (i.e., surface roughness, Bowen ratio, and albedo) for the meteorological measurement site that is used to represent meteorological site conditions. Chapter 2.3.4 of AQD's *Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits* also indicates that surface characteristics using AERSURFACE can be used for air permit applications. The GeoTIFF file for Oklahoma containing the land cover data is used as input for AERSURFACE. AQD's modeling guidance document also recommends the following input conditions for running AERSURFACE:

- Center the land cover analysis on the meteorological measurement site.
- Analyze surface roughness within 1 km of measurement site.
- Utilize one sector determining the surface roughness length.
- Temporal resolution of the surface characteristics should be determined on a monthly basis.
- The region does not experience continuous snow cover for most of the winter.
- The Mesonet site is not considered an airport.
- The region is not considered an arid region.
- Utilize the default season assignment (winter=Dec, Jan, Feb; Spring=Mar, Apr, May; Summer=Jun, Jul, Aug; Fall=Sep, Oct, Nov)

Background Concentrations

For the PSD NAAQS analysis, background concentration data was added to impacts from the proposed project and regional sources. AQD provided representative data for NO_2 and $PM_{2.5}$.

The maximum background concentrations are from the North Tulsa monitoring station 40-143-1127. Values are listed in the table following. For short-term standards, the conservative approach was to add the maximum background concentrations to the NAAQS modeling results. Due to the form of the NO_2 short-term standard, EPA provides other options as detailed in the *Additional Clarification Regarding the Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (EPA 2011) memorandum. The monitor is located approximately 10 km north of the HFTR East Refinery and HFTR West Refinery. Other nearby facilities in Tulsa including Empire, Covanta, PSO Tulsa, Veolia Energy and Aaon are similarly situated. The winds mainly blow from a southwesterly to southeasterly direction and the aforementioned facilities impact the monitor when the wind blows from that direction.

Therefore, full impact modeling when taking into account background concentrations will have the potential for double-counting impacts from those facilities. Because the monitor is located on the north side of the Tulsa metropolitan statistical area, it closely represents the metropolitan area and industrial presence in the Tulsa area.

Background Concentration Data

Pollutant	Basis	Period of Record[1]	Background Concentration
NO_2	1-hour average daily maximum concentration (98^{th} percentile) averaged over 3 years	2016 - 2018	37.1 ppb (69.8 $\mu g/m^3$)
	Maximum annual average	2018	7.50 ppb (14.0 $\mu g/m^3$)
$PM_{2.5}$	24-hour average concentration (98^{th} percentile) averaged over 3 years	2016 - 2018	23.7 $\mu g/m^3$
	Three-year annual average concentration	2016 - 2018	9.67 $\mu g/m^3$

For further NO_2 modeling refinement, rather than use a single monitored background value, 1-hour average ozone and NO_2 background concentration data from the Tulsa monitor, on an hour-by-hour basis, were used in the model to address the spatial and temporal nature of cumulative NO_2 impacts. These hourly concentration files provided by AQD were calculated based on the five year average of the 98^{th} percentile values from a Seasonal, Hour-of-Day, and Day-of-Week review of the 2011-2015 data.

<u>Good Engineering Practice and Building Downwash Evaluation</u>

The dispersion of a plume can be affected by nearby structures when the stack is short enough to allow the plume to be significantly influenced by surrounding building turbulence. This phenomenon, known as structure-induced downwash, generally results in higher model-predicted ground-level concentrations in the vicinity of the influencing structure. Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in OAC 252:100-8-1.5. GEP stack height is defined as the greater of 65 meters or a height established by applying the formula Hg = H + 1.5L, where:

Hg = GEP stack height,
H = height of nearby structures, and
L = lesser dimension (height or projected width) of nearby structures,

or by a height demonstrated by a fluid model or a field study that ensures that emissions from a stack do not result in excessive concentrations of any pollutant as a result of atmospheric downwash, wakes, or eddy effects created by the source itself, nearby structures, or nearby terrain features.

The model utilizes the EPA Building Profile Input Parameters (BPIP) program with the plume rise model enhancements (PRM). BPIP-PRIME determines the effect of building downwash on each plume in calculation of maximum impacts.

Meteorology and Surface Characteristics

AQD supplied five years of AERMET (Version 18081) pre-processed meteorological data (2011-2015) from the ASOS site at Richard L. Jones, Jr. Airport (KRVS: 2011–2015), Tulsa, Oklahoma. The airport ASOS site is located about 8.5 km south from the HFTR East Refinery and about 10.5 km south-southeast from the HFTR West Refinery. Depending on the design value modeled, either a single 5-year hourly sequential meteorological data set or five single-year hourly sequential meteorological data sets were utilized. When using AERMET to prepare the meteorological data for AERMOD, the surface characteristics (Albedo, Bowen Ratio, and Surface Roughness Length) for the primary (ASOS) and secondary (NCDC-ISD) meteorological sites were determined using AERSURFACE.

In the original PSD construction permit, the Class I area screening using AERMOD modeling utilized the same hourly sequential meteorological data set utilized in the Class II modeling. The Class I area screening modeling with CALPUFF modeling utilized an ISCST3 meteorological (MET) data file generated with the preprocessor PCRAMMET. For this study, three years of ISCST3-type meteorological data were used in a ‘screening’ version of CALPUFF. RAMMET View 8.1.0 was used to combine three years of surface and upper air ISCST3 MET data. The data were downloaded from the WebMET website.

Default Site Parameters Modeled In CALPUFF

Parameter	**Value**
Anemometer Height [m]	6.1
Minimum Monin-Obukhov Length [m]	100.0
Surface Roughness Length (Measurement Site) [m]	1.0
Surface Roughness Length (Application Site) [m]	1.0
Noon-Time Albedo	0.2075
Bowen Ratio	1.625
Anthropogenic Heat Flux [W/m_2]	19.0
Fraction of Net Radiation Absorbed at the Ground	0.27

The surface station at the Oklahoma City Will Rogers World Airport was selected and three years from 1986-1988 were used to compile the CALPUFF ready MET files. The closer MET station in Tulsa was not selected because the corresponding upper air data were not available. Due to the distances involved with the CALPUFF modeling, the surface wind data at Oklahoma City are considered representative of conditions near Tulsa. The anemometer height for this station is equal to 6.1 meters. Other site parameters were automatically selected after choosing “urban” as the land use type. The CALPUFF ready output files were generated assuming no precipitation. This file was then imported into CALPUFF.

Receptor Grid

Class II

A Cartesian receptor grid was developed for Class II air dispersion modeling. The Cartesian receptor grid was defined using UTM NAD83 Zone 15. The receptor grids were designed to capture the maximum pollutant impact locations. Following AQD modeling guidance, a receptor grid was placed with spacing of 100 m out to 1 km, 250 m out to 2.5 km, 500 m out to 5 km, 750 m out to 7.5 km, and 1 km out to the edge of the modeling domain. The edge of the modeling domain was determined to be approximately 20 km from the facility for NO_2, and approximately 12 km from the facility for PM_{10}, $PM_{2.5}$ and CO. Discrete property line receptors were spaced no further than 100 meters apart.

Class I

The Tier I significance modeling for Class I areas from the original PSD construction permit conducted using AERMOD utilized a Polar receptor grid comprised of a circle of receptors with a 50 km radius. There were a total of 360 receptors, spaced along each degree of the circle. The center point of the grid was located at UTM NAD83 Zone 15, coordinates 228430, 4002440. The polar grid was then converted to a series of discrete Cartesian receptors. Only the receptors within the Class I directional ranges were used to determine maximum Class I impacts for the analyses.

For the CALPUFF modeling from the original PSD construction permit, the recommended method of adding ring receptors was not used. Instead, discrete receptors from the four (4) Class I areas were obtained from AQD and imported into the CALPUFF model. Gridded receptors were not included.

<u>Source Input Parameters</u>

The following table lists the facility source parameters used as AERMOD model inputs. The modeling analysis includes emissions from combustion sources including boilers, heaters, gas engines, and flares. Each stack was modeled as a point source. The AERMOD source parameters for modeling include source coordinates in UTM NAD83, base elevation above MSL, stack height, stack gas exit velocity, stack diameter, and stack gas temperature.

HFTR has considered either the option of installing a new hydrogen plant at West Refinery with shutdown of most of the No. 2 Platformer heaters, or an option to retain the No. 2 Platformer. In the PSD Modeling Study, the impacts of only the hydrogen plant scenario is presented, including retaining Plat heaters 3 & 4.

Existing gas engines are a special case in terms of modeling. All are considered “not affected” in terms of the project, but the PDA Compressor, H_2 Recycle Compressor, #2 CT Circ Pump Engine, #3 CT Circ Pump Engine, and #6 CT Circ Pump Engine have been electrified and will have contemporaneous emission reductions with the project. Credit for these emission reductions was only used in the PM_{10} and $PM_{2.5}$ increment modeling analyses. In the new hydrogen plant case, shutdown of No. 2 Platformer heaters 1/2, and 5-7 will provide additional emission reductions. Credit for these emission reductions was only used in the PM_{10} and $PM_{2.5}$ increment modeling analyses.

Each type of modeling impact analysis (SIL, NAAQS, increment) utilized a different set of project emissions rates, calculated in units of gram per second (g/s). For the SIL analysis, project emissions increases were modeled as the difference between the potential-to-emit (PTE) and the baseline actual emissions (BAE), for each pollutant. For the NAAQS analysis, the project PTE, regional source PTE, and background concentration data were included. For the increment analysis, project PTE and regional source PTE or actual emissions from sources installed after the PSD major and minor baseline dates were included. Short-term emission rates were used for each pollutant with 1-hour, 3-hour, 8-hour, or 24-hour averaging time standards, as applicable. Annual emissions rates were used for each pollutant with annual averaging time standards. Updates to Appendix W allow for use of actual emission data for nearby sources in NAAQS analyses.

The SIL analyses required only the modeling of project emission increases, determined by calculating the difference between the 2010-2011 baseline emission rates and the proposed PTE of each affected or modified emission unit. New units constructed for the project have zero baseline emission rates and are modeled with emission increases up to full PTE. Units constructed within 24 months prior to project operation, are assumed have zero project emission increases, with baseline emissions equivalent to PTE. For example, this situation would apply to Boiler 10 at the West Refinery. In AERMOD, project emission increases are typically denoted by “P” at the end of the AERMOD source ID.

The NAAQS analysis required the modeling of PTE, or the maximum amount of an air contaminant that can be emitted by a source. For an existing modified or affected source, the PTE is the sum of the baseline emission rates and the project emission increases. To reduce the number of modeling files and iterations required in AERMOD, each existing emission source was duplicated and co-located to differentiate between the “baseline” emissions for the source, typically denoted by “B” at the of the AERMOD source ID and the project emissions increase from the source, denoted by the “P” at the end of the AERMOD source ID. This separation also serves the purpose of incorporating project emission increases into the full impact analysis to determine that the project does not cause nor contribute to any potential NAAQS exceedance. This allows SIL, NAAQS, and PSD increment to be modeled together in separate source groupings to streamline the modeling work

Analyses was performed on facility and selected nearby regional sources to determine which units were installed before the major and minor source baseline dates. Emissions permitted before the baseline dates were not included in the PSD increment analysis.

HFTR East Refinery & HEP Modeling Source Parameters

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (ºK)
	Easting (m)	Northing (m)					
Project Units - New							
CCR Helper Heater (new)	229947	4000693	193	22.9	0.76	9.53	478
NHDS Helper Heater (new)	229670	4000663	192	22.9	0.46	10.59	478
DHTU Helper Heater (new)	229945	4000602	195	22.9	1.00	11.07	478
Project Units - Affected or Modified							
DHTU Charge Heater 1H-101	229947	4000617	195	42.7	1.46	10.10	583
CCR Charge Heater 10H-101, #2-1 Interheater 10H-102, #2-2 Interheater 10H-103	229950	4000673	195	37.8	1.77	19.86	561
CCR Stabilizer Reboiler 10H-104	229951	4000700	195	37.8	1.37	21.00	533
Naphtha Splitter Reboiler Heater	229975	4000704	195	34.7	2.06	5.84	533
CCR Interheater #1 10H-113	229971	4000688	195	38.1	2.53	5.24	466
Boiler #1	229910	4001435	193	18.2	1.83	13.63	422
Boiler #2	229918	4001435	193	18.2	1.83	13.63	422
Boiler #3	229936	4001434	193	18.2	1.83	13.63	422
Boiler #4	229945	4001434	193	18.2	1.83	13.63	422
Sulfur Recovery Unit/Tail Gas Treating Unit (SRU/TGTU) #1	229823	4000611	192	61.0	0.61	5.88	501
Sulfur Recovery Unit/Tail Gas Treating Unit (SRU/TGTU) #2	229762	4000608	192	30.8	0.76	7.65	341
NHDS Charge Heater 02H-001	229664	4000659	192	30.5	1.13	9.84	693
NHDS Stripper Reboiler 02H-002	229658	4000653	192	29.3	1.13	12.74	791

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (ºK)
	Easting (m)	Northing (m)					
Vacuum Tower Heater	229956	4001097	194.5	53.3	3.51	1.60	450
CDU Atmospheric Tower Heater	229956	4001088	194.5	44.1	2.83	11.60	560
FCCU Charge Heater B-2	229950	4000883	194	41.9	2.13	9.76	616
FCCU Regenerator	229945	4000861	194	46.0	1.52	15.52	333
Unifiner Charge Heater H-1	229938	4000775	193	14.6	1.16	10.72	783
Scanfiner Charge Heater 12H-101	229954	4001001	193	13.7	1.07	7.95	585
VCU Terminal Loading	229352	4000605	193	13.7	2.44	3.08	1,033

HFTR West Refinery Modeling Source Parameters

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (ºK)
	Easting (m)	Northing (m)					
Project Units - New							
Modified PDA to ROSE, new heater	228750	4003806	195.1	22.9	1.00	16.83	478
Hydrogen Plant Reformer Heater	228143	4004066	195.0	22.9	1.52	13.30	533
Project Units - Affected or Modified							
#7 Boiler	228660	4003895	195.1	18.3	1.52	12.13	430
#8 Boiler	228660	4003903	195.1	18.3	1.52	13.57	481
#9 Boiler	228658	4003859	195.1	24.4	1.52	11.37	403
#10 Boiler	228588	4003843	195.1	15.2	1.45	21.83	459

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (ºK)
	Easting (m)	Northing (m)					
CDU Atmospheric Tower Heater - North Stack	228262	4003837	194.3	41.2	2.26	9.04	522
CDU Atmospheric Tower Heater - South Stack	228261	4003822	194.3	41.2	2.26	8.98	518
CDU #1 & #2 Vacuum Tower Heaters	228279	4003823	194.5	38.1	2.26	7.59	718
EG-5747	228750	4003806	195.1	6.71	0.15	13.20	589
Unifiner Charge Heater	228239	4003969	194.6	20.1	1.37	4.89	574
Unifiner Stripper Reboiler Heater	228239	4003982	194.3	23.5	1.52	5.84	522
C-2719	228288	4003961	194.5	7.62	0.21	7.26	547
No. 2 Platformer Charge Heater (PH-1/2)	228247	4004021	193.9	27.7	2.13	7.36	884
No. 2 Platformer Charge Heater (PH-3)	228238	4003989	194.2	15.2	1.37	5.67	673
No. 2 Platformer Charge Heater (PH-4)	228237	4003995	194.2	15.2	1.52	3.83	455
No. 2 Platformer Charge Heater (PH-5)	228262	4004030	193.9	27.4	2.13	4.59	732
No. 2 Platformer Charge Heater (PH-6)	228251	4004029	193.9	25.9	1.52	5.06	769
No. 2 Platformer Charge Heater (PH-7)	228246	4004013	193.9	30.8	1.13	9.13	1,039
Coker Drum Charge Heater (B-1)	228528	4004114	195.1	34.1	1.68	5.79	621
Coker Preheater (H-3)	228524	4004106	195.4	27.7	1.22	5.26	555
LEU Raffinate Mix Heater (H101)	229176	4003722	195.1	27.4	0.91	6.36	543
LEU Extract Mix Heater (H102) North Stack	229185	4003728	195.1	38.1	1.62	5.98	558
LEU Extract Mix Heater (H102) South Stack	229185	4003718	195.2	38.1	1.62	6.03	563

	UTM Coordinate		Base Elevation (m)	Final Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp (ºK)
	Easting (m)	Northing (m)					
LEU Hydrotreater Charge Heater (H201)	229176	4003712	195.1	30.5	1.62	2.32	619
MEK - Wax Free Oil Heater	229194	4003727	195.2	34.1	1.83	5.06	478
MEK - Soft Wax Heater (H-2)	229202	4003723	195.2	19.0	1.07	9.08	483
EG-5579	228851	4003794	195.0	7.62	0.31	2.65	616
EG-5156	228578	4004020	195.0	7.62	0.31	0.001	644
EG-5152	228605	4003885	195.0	5.49	0.31	0.001	616
EG-5154	228617	4003889	195.0	5.49	0.15	14.33	616

HFTR emissions permitted before the applicable major source baseline dates were excluded from increment analyses. In addition to the new sources for this project, the following sources were included in the increment review.

	NO_2	$PM_{2.5}$
HFTR East Refinery		
Naphtha Splitter Reboiler Heater	+2019	+2019
CCR Interheater #1 (10H-113)	+2005	
Sulfur Recovery Unit (SRU) #2	+2006	
NHDS Charge Heater	+2006	
NHDS Reboiler Heater	+2006	
Scanfiner Charge Heater	+2004	
CDU Atmospheric Tower Heater		+2019
FCCU Charge Heater B-2	+2021	+2021
DHTU		+2017
FCCU		+2021
HEP		
Loading racks / VCU	+2012	
HFTR West Refinery		
#3 Boiler	-2014	-2014
#4 Boiler	-2014	-2014
#10 Boiler	+2014	+2014
PDA Propane Compressor	-2013	-2013
Unifiner H2 Recycle Compressor	-2013	-2013
No. 2 Platformer Charge Heater (PH-4)	+2014	+2014
No. 2 Platformer Charge Heater (PH-5)	+1990	-2015
Coker Drum Charge Heater (B-1)	+1992	
Coker Preheater (H-3)	+1995	
#2 CT Circ Pump Engine	-2013	-2013
#3 CT Circ Pump Engine	-2014	-2014
#6 CT Circ Pump Engine	-2017	-2017
#6 CT Spray Pump Engine	-2013	-2013

Reductions in actual emissions are credited for shutdown sources. Only the proposed new sources and associated emission increases at existing sources are included in the increment analysis for $PM_{2.5}$.

Regional sources excluded from increment analysis include PSO Tulsa, Empire Castings, and all but the most recently permitted turbine at Veolia (permitted 2007). Increment analysis must identify impacts of actual emissions, but for screening the higher potential emissions were used except where actual operating data was provided by AQD.

Urban/Rural Classification

Section 7.2.1.1 of the GAQM (2017) provides the basis for determining the urban/rural status of a source. For most applications, the land use procedure described in Section 7.2.1.1(b) is sufficient for determining the urban/rural status. However, there may be sources located within an urban area, but located close enough to a body of water to result in a predominantly rural classification. In those cases, the population density procedure may be more appropriate. Only the following land use procedure is used to assess the urban/rural status of the source.

- Classify the land use within the total area, A_o, circumscribed by a 3-km radius circle about the source using the meteorological land use typing scheme proposed by Auer.
- If land use Types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (single-family compact residential), and R3 (multifamily compact residential) account for 50 percent or more of A_o, use urban dispersion coefficients; otherwise, use appropriate rural dispersion coefficients.

Based on visual inspection of the USGS 7.5-minute topographic map of the project site location, it was conservatively concluded that over 50 percent of the area surrounding the project may be classified as urban. Accordingly, the urban dispersion modeling option is used in the AERMOD PRIME model.

Regional Inventory Emissions and Source Parameters

AQD provided an inventory of source parameters and emission rates for each pollutant for nearby sources in the Tulsa region. The source databases reviewed including all sources within 100 km of the facility and those sources excluded from the modeling analysis is available for review upon request. Stack locations, source parameters and emission rates were provided for modeling. The stack location coordinates were independently researched for inconsistencies with the site address prior to use in the modeling. Where information differed from the AQD database, corrections were entered to the inventory. Google Earth was used to corroborate or correct regional source facility coordinates provided in the ARIES file.

All regional sources within 10 km were included in the analysis while all regional sources outside of 50 km were excluded from the analysis. The AQD narrowed the list of existing nearby sources required to be included in the NAAQS and increment modeling analyses to only those that would be expected to have a significant concentration gradient within the modeling domain for those sources outside of 10 km, but within 50 km. The facility eliminated two sources from the list provided by AQD using the “10 D Rule,” which eliminates sources from the modeling review when the emissions (TPY) are less than 10 times the distance (in kilometers) from the modeled facility: “BIZJET INTL” and “ST FRANCIS HOSP”. Based on the updates to Appendix W, these sources would be considered other sources that are represented by the background concentration. EPA comments and AQD responses to EPA comments concerning sources excluded in the original PSD construction permit modeling analyses are available as part of the permit record of the original PSD construction permit. A review of nearby/other sources constructed/modified since issuance of the original PSD construction permit did not yield any additional sources with significant impacts within the modeling domain.

Regional sources are only included in the Class II full impact modeling analyses. The regional source emission rates are permitted, potential-to-emit values for short-term modeled rates, unless otherwise noted. AQD provided operating factors for some units to be used on annual emission rates. The operating factors account for the assumption that equipment does not operate 8,760 hours per year. With AQD approval, some units were allowed to be "excluded as intermittent" from 1-hr short-term impacts in the modeling study.

Significance Analysis

Dispersion modeling analysis usually involves two distinct phases; a preliminary analysis and a full impact analysis. The preliminary analysis models only the significant increase in potential emissions of a pollutant from a proposed new source, or the significant net emissions increase of a pollutant from a proposed modification. The results of this preliminary analysis determine whether the applicant must perform a full impact analysis, involving the estimation of background pollutant concentrations resulting from existing sources and growth associated with the proposed project. Specifically, the preliminary analysis:

- determines whether the applicant can forego further air quality analyses for a particular pollutant;
- may allow the applicant to be exempted from the ambient monitoring data requirements; and
- is used to define the impact area within which a full impact analysis must be carried out.

In general, the full impact analysis is used to project ambient pollutant concentrations against which the applicable NAAQS and PSD increments are compared, and to assess the ambient impact of non-criteria pollutants. The full impact analysis is not required for a particular pollutant when emissions of that pollutant would not increase ambient concentrations by more than the applicable significant impact level (SIL).

For the pollutants that exceeded the SERs, NO_2, $PM_{2.5}$, PM_{10} and CO, preliminary modeling was completed for comparison to the SIL. For pollutants with maximum off-site ambient concentrations less than the applicable SIL, no further impact assessment is required. If impacts are greater than the SIL, then a full impact modeling analysis is required, including a NAAQS modeling analysis (Class II areas) and a PSD increment consumption analysis (Class I and Class II areas). Air quality modeling for ozone impacts is not required because VOC emission increases from the project will not exceed 100 TPY.

Using EPA's May 2014 "Guidance for $PM_{2.5}$ Permit Modeling," a full impact analysis for $PM_{2.5}$ is not required if: (1) the difference between the $PM_{2.5}$ background concentration and the $PM_{2.5}$ NAAQS is greater than the $PM_{2.5}$ significance impact level; and (2) the modeled impacts of $PM_{2.5}$ from the project would not increase ambient concentrations by more than the $PM_{2.5}$ significant impact level (SIL). The same analysis was completed for NO_2, CO and PM_{10}. As demonstrated by the following table, a full impact analysis is not required for CO or PM_{10}.

The full impact analysis considers emissions from existing sources, as well as the emission increases associated with the project, to comply with NAAQS and PSD increment consumption analyses. This required the addition of background concentration levels and regional source emissions, as provided by AQD.

Pollutant	Averaging Period	Max Project Impact $\mu g/m^3$	SIL $\mu g/m^3$	Full Impact Analysis Required?
NO_2	1-hr	96.5	7.5	Yes
	Annual	8.2	1	Yes
PM_{10}	24-hr	4.9	5	No
	Annual	0.7	1	No
$PM_{2.5}$	24-hr	4.2	1.2	Yes
	Annual	0.8	0.3	Yes
CO	1-hr	109	2,000	No
	8-hr	76.0	500	No

Full Impact Analyses

The next step was to perform a full impact analysis. The full impact analysis considers emissions from existing sources, as well as the emission increases associated with the project, to comply with NAAQS and increment consumption analyses. A Class II full impact analysis was required for NO_2 and $PM_{2.5}$ because the SILs were exceeded. The full impact analysis required more refined modeling to compare impacts to the Class II National Ambient Air Quality Standards (NAAQS). For the NAAQS analysis, modeling results for the combined criteria pollutant impacts from HFTR East, HFTR West, HEP and regional sources were added to corresponding background concentrations.

Modeling results for NAAQS and Class II increment analyses are presented following. MAXDCONT files were used to assist in demonstrating compliance with the 1-hour NO_2 and $PM_{2.5}$ 24-hour NAAQS. The MAXDCONT files were used to pair impacts in time in space at receptors to demonstrate that project impacts are not significant at the occurrence of a NAAQS or increment exceedance. The results are presented in the corresponding tables following.

Compliance with the NAAQS is demonstrated when: 1) modeled impacts are below the NAAQS standards (for example on the HFTR East Refinery and HFTR West Refinery property lines) and, 2) modeled impacts from the proposed Project emission increases are not significant at any locations where the NAAQS is exceeded (for example by a regional source).

For purposes of NAAQS compliance, where background concentrations are added to modeled impacts, AQD provided guidance on minimizing double counting due to the nearby facility emission impacts on the background monitoring data. For sources impacting the monitor, modeled emission rates were reduced by a factor representing actual emissions times the source operating factor. EPA comments and AQD responses to EPA comments concerning the AQD guidance related to double counting of source impacts in the original PSD construction permit modeling analyses are available as part of the permit record of the original PSD construction permit. Updates to Appendix W allow for use of actual emissions rather than potential emissions for nearby sources, for reducing the number of nearby sources to be explicitly modeled, and identifying the majority of sources as other sources that are represented by air quality monitoring data. These policies are considered more conservative than how the nearby sources to be explicitly included in the modeling for the original PSD construction permit.

The modeling results for 1-hour and annual NO_2 are presented here. There were 7 potential modeled violations of the NAAQS confined to one receptor within the modeling domain out to the highest 14th High impact. The maximum 1-hour NO_2 NAAQS impacts for the one receptor, paired with the corresponding project contribution in time and space, is shown in the following table. Each of the potential modeled violations were examined and the project did not have a significant contribution at any of them. The modeled annual NO_2 maximum impact did not exceed the NAAQS at any receptor and did not require further analysis.

NO_2 Max NAAQS & Project Contribution **NO_2 Max NAAQS & Project Contribution**

Pollutant	**Averaging Period**	**NAAQS μg/m³**	**Max Impact μg/m³**	**E UTM m**	**N UTM m**	**Project Contribution[1] μg/m³**
NO_2	1-hour	188	198.6	247430	4009440	0.012
			196.4	247430	4009440	0.003
			194.5	247430	4009440	0.003
			193.1	247430	4009440	0.004
			191.7	247430	4009440	0.005
			190.3	247430	4009440	0.014
			188.7	247430	4009440	0.005
	Annual	100	42.3	230330	4005140	N/A

[1]1-hour NAAQS and project contribution paired in time & space using MAXDCONT.

$PM_{2.5}$ full impact modeling was performed to demonstrate compliance with the 24-hour and annual NAAQS standards. There were 1011 potential modeled violations of the $PM_{2.5}$ 24-hour NAAQS within the modeling domain compared to 29 receptors, with the highest value 53.49 μg/m³. There were 46 potential modeled violations of $PM_{2.5}$ annual NAAQS. The maximum NAAQS impact of these receptors, paired with the corresponding project contribution in time and space, is presented in the following table. For the $PM_{2.5}$ 24-hour NAAQS, the value at each receptor with the maximum project contribution is shown. For the $PM_{2.5}$ annual NAAQS, the 5 locations with highest project contribution, and the top 5 locations with the highest value are shown. The project was not significant at any of the receptors where a potential modeled violation occurred.

$PM_{2.5}$ Max NAAQS & Project Contribution

Pollutant	Averaging Period	NAAQS µg/m^3	Max Impact µg/m^3	E UTM m	N UTM m	Project Contribution[1] µg/m^3
	24-hour	35	39.88	228430	4002240	0.18
			40.63	228430	4002340	0.31
			40.46	228430	4002440	0.45
			49.68	228530	4002240	0.20
			56.70	228530	4002340	0.11
			36.04	228430	4002140	0.29
			37.71	228430	4002540	0.29
			38.14	228530	4002140	0.25
			46.85	228530	4002440	0.08
			38.58	228530	4002540	0.03
			37.47	228630	4002240	0.28
			39.91	228630	4002340	0.14
			40.30	228630	4002440	0.07
			35.92	228630	4002540	0.06
			46.21	228030	4005040	0.19
			40.59	228030	4005140	0.74
			38.24	236430	4007940	0.11
			38.78	224430	3995940	0.00
			41.90	224430	3995440	0.11
			42.05	222430	4003440	0.02
			56.21	238430	4004440	0.02
			39.32	221430	3990440	0.01
			43.93	221430	3989440	0.02
			37.24	221430	3988440	0.01
			45.68	220430	3990440	0.00
			36.73	220430	3991440	0.00
			54.05	220430	3989440	0.00
			56.25	220430	3988440	0.08
			43.18	220430	3987440	0.05
	Annual	12	20.27	238430	4004440	0.04
			18.29	224430	3995440	0.04
			16.62	224430	3995940	0.04
			16.47	220430	3989440	0.02
			16.02	220430	3989440	0.02
			12.05	228130	4005240	0.25
			12.36	228130	4005140	0.25
			12.21	228130	4005040	0.25
			12.55	228030	4005240	0.24
			13.84	238030	4005140	0.23

[1] - 24-hour NAAQS and project contribution paired in time & space using MAXDCONT.

PSD Increment Consumption

To complete the PSD increment consumption analysis, the criteria pollutant emissions increase above the PSD baseline level for each emission source considered in the study must be modeled. The increments are more stringent for Class I areas such as National Parks and wilderness areas, than for Class II areas, such as the area near the site. A modeling analysis using potential emissions is usually conducted and if compliance is unable to be demonstrated than a modeling analysis using actual emissions is conducted.

Not all emission sources are assumed to be increment-consuming. For each pollutant, the PSD increment analysis includes only the project emission increases for all units built before the applicable major and minor source baseline dates and PTE or actual emissions for all sources built after the applicable major and minor source baseline dates.

The major source baseline date for NO_2 is February 8, 1988. The major source baseline date for $PM_{2.5}$ is October 20, 2010. All emission increases and decreases at major sources after the major source baseline dates must be included in the regional increment consumption analysis. The Tulsa County NO_2 minor source baseline date was triggered in Air Quality Control Region (AQCR) 186, including Tulsa County, on June 23, 1989. Minor source emission changes after the minor source baseline dates must be included in the regional increment consumption analysis. The $PM_{2.5}$ minor source baseline was triggered by the HFTR and HEP PSD application on October 14, 2014.

Compliance with the PSD increment consumption analysis is shown when: 1) total increment consumption after the baseline date does not exceed the increments and 2) impacts from proposed project emission increases are not significant at any locations where the increment thresholds are exceeded (i.e. by a regional source).

PSD increment modeling results for annual NO_2 increment are presented in the following table. The maximum impact does not exceed the increment. Therefore, no further modeling was required.

NO_2 Class II Increment Modeling Results

Pollutant	Averaging Period	Increment µg/m³	Max Impact µg/m³	Increment Exceeded?
NO_2	Annual	25	15.6	No

PSD increment modeling results for 24-hour and annual $PM_{2.5}$ increments are presented following. The increment was not exceeded at any receptor.

$PM_{2.5}$ Class II Increment Modeling Results

Pollutant	Averaging Period	Increment µg/m³	Max Impact µg/m³	Increment Exceeded?
$PM_{2.5}$	24-hour	9	4.5	No
	Annual	4	0.9	No

PSD Monitoring Exemption Thresholds

On a case-by-case basis, AQD has the authority to require pre-construction air quality monitoring for background concentration data, unless modeled impacts from project emission increases, or existing ambient concentrations, are below the PSD monitoring exemption thresholds. Modeling was completed for comparison to the exemption thresholds as shown in the table below. While some of the monitoring exemption thresholds are exceeded by modeled impacts, representative background concentration data are available for all pollutants and averaging periods from the North Tulsa monitor (40-143-1127). Therefore, pre-construction monitoring is not needed.

Pollutant	Averaging Period	Monitoring Exemption Threshold µg/m³	Maximum Impacts µg/m³	Threshold Exceeded?
NO_2	Annual	14	8.2	No
CO	8-hour	575	76.0	No

Ozone Impacts Assessment

Under OAC 252:100-35(c), an increase in NO_X or VOC of 100 TPY triggers an ambient impact analysis for ozone, including gathering of ambient air quality data. That ambient monitoring is already being performed in the Tulsa metro area, therefore, that requirement is adequately fulfilled. The changes related to this modification were not significant enough to revise the previous determination and the discussion is included for historical purposes. EPA comments and AQD responses to EPA comments concerning the ozone impact assessment in the original PSD construction permit are available as part of the permit record of the original PSD construction permit. Updates to Appendix W and EPA guidance has addressed single source ozone determinations using modeled emission rates for precursors (MERPS). However, this permit was submitted during the transition period for these updates.

The calculated NO_X emissions increase of 737 TPY result mostly from increased utilization of existing units. Added NO_X emissions from new heaters and heater modifications of capacity would be 51 TPY. The net increase does not take into account significant reductions in both NO_X and VOC required by the recent facility Consent Decree.

The area will have a rather large decrease in actual NO_X emissions from implementation of Consent Decree requirements. These projects include retirement of Boilers 1 through 4, installation of two flare gas recovery units (FGRU) which decreased the amount of gas being flared, and emissions reductions at the Fluid Catalytic Cracking Unit (FCCU). The reduction in actual emissions from those activities was 1,001 TPY NO_X. While the consent decree explicitly states that netting analyses shall not include emission reductions achieved through the consent decrees, it does not specifically address ambient impact analyses. It was determined in the original permit that reductions in ambient impacts should be considered in the evaluation of actual changes in ozone impacts for the facility, because impact analyses do not force technology nor require controls but instead inform the community of the likely changes in ambient pollutant concentrations that may result from the facility. Also, the changes in ambient impacts due to the emissions reductions will be observed in the monitoring data.

Ozone analyses typically use a relative response approach to impact assessment. A baseline inventory is modeled to provide an initial value. The inventory is then modified to reflect the future projected actual emissions and modeled again. The difference in projected ozone values is added or subtracted from local monitors to provide a rough assessment of ambient ozone impacts. In evaluating projected ambient ozone concentrations, inclusion of the federally contemporaneous reductions that have occurred at the facility is fully consistent with the logic that requires contemporaneous increases and decreases to be considered in project evaluations in the first place. It provides a more accurate depiction of facility-wide impacts over time. In this instance, reductions in NO_X emissions are well in excess of increases.

It is concluded that the proposed expansion will not have a deleterious effect on ambient ozone concentrations in the Tulsa area. The design value has decreased significantly over the last five years (2013-2017) at the Tulsa monitor (40-143-1127) from 80 ppb to 64 ppb.

VIII. OTHER PSD ANALYSES

A. Evaluation of Class I Area Impacts

Class I areas are provided special protection under PSD by Air Quality Related Values (AQRVs) defined and enforced by the Federal Land Manager (FLM). The FLM may recommend against issuance of a PSD permit if a source adversely impacts the AQRVs. Potential AQRV impacts are screened per the FLM guidance in *Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report – Revised (2010)* (NPS 2010). For sources located more than 50 km from a Class I area and passing screening under the 10D Rule there is a presumptive No Adverse Impact. Modeling may still be required to demonstrate compliance with EPA Class increment thresholds.

Under the 10D Rule, the equation Q/D<10 is applied, where:

> Q is equal to the sum of the emission increases of NO_X and PM_{10} that result from the proposed project (in TPY).
>
> D is the distance from the source to the Class I Area (in km).

The maximum project emission increases based upon maximum hourly emissions estimates, NO_X + PM_{10} = 656 TPY, were compared to the minimum Class I distance, 230 km. The Q/D value (2.9) does not exceed 10. Therefore, a refined Class I area analysis evaluating impacts to the AQRVs, including deposition and visibility, is not required. Note that this analysis does not account for the large, contemporaneous reductions in actual NO_X and SO_2 emissions that have recently occurred at the HFTR West refinery.

This section addresses the Class I significance modeling analysis required for the PSD Modeling Study. AERMOD was used to determine compliance with the Class I significance thresholds. EPA requires a screening analysis for Class I SILs if a facility is within 300 km of a Class I area. This analysis is a tiered analysis to reduce the burden on the applicant. For Tier I, facilities can use AERMOD as a screening model to determine impacts from the project emission increases out to 50 km from the facility. In the original PSD construction permit a screening analysis using CALPUFF was conducted for $PM_{2.5}$. However, due to a correction of the SIL the screening analyses using AERMOD have demonstrated that the facility will not significantly affect any of the Class I Areas.

Location of Class I Areas within 300 Kilometers

The nearest Class I areas within 300 km of the project site are the Caney Creek Wilderness (250 km), the Hercules-Glades Wilderness (280 km), the Upper Buffalo Wilderness (230 km), and the Wichita Mountains Wilderness (280 km). The Class I area details are summarized following.

Class I Areas Within 300 km of HFTR Facilities

Class I Area	State	Distance (km) & Direction From HFTR
Caney Creek	Arkansas	250 km East-Southeast (137^o - 140^o)
Hercules-Glades Wilderness Area	Missouri	280 km Northeast (77^o - 78^o)
Upper Buffalo Wilderness Area	Arkansas	230 km East (97^o - 99^o)
Wichita Mountains Wildlife Refuge	Oklahoma	280 km Southwest (239^o - 241^o)

The Class I area impact screening analysis requires modeling of the project's impacts at 50 km to determine if the project's impacts exceed the Class I SILs. The maxima were obtained in the angular direction of the Class I areas. If impacts are less than the SILs, no further analysis is necessary; if they exceed the SILs, CALPUFF modeling is used to determine project impacts.

Model Results for Class I Tier I Significant Impact Analysis

Pollutant	Averaging Period	Significant Impact Level ($\mu g/m^3$)	Max Class I Impacts ($\mu g/m^3$)	Exceeded in Direction of Class I Area?
NO_2	Annual	0.1	0.04	No
PM_{10}	24-hour	0.3	0.11	No
	Annual	0.2	0.01	No
$PM_{2.5}$	24-hour[1]	0.27	0.11	No
	Annual[1]	0.05	0.01	No

[1] - These values were updated to reflect the current EPA guidance.

B. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, and Visibility

Commercial, Residential, and Industrial Growth Analysis

The intent of a growth analysis is to assess air quality impacts due to residential and commercial growth due directly to a proposed modification or new construction. If such activity requires a large new work force, such growth would result due to the influx of families associated with the workforce.

An increase in the workforce will be observed during construction, but the increase in permanent employees is expected to be small. Because the project is located in an urban setting, it is likely that the majority of any construction workers or new permanent employees will be hired locally and that the true number of relocating families will be quite small. In consideration of these issues, it is estimated that air quality impacts associated with growth will be minimal (if detectable at all).

Soils & Vegetation Analyses

The effect of the proposed project emissions on local soils and vegetation were addressed through comparison of modeled impacts to the secondary NAAQS for NO_2, $PM_{2.5}$, and PM_{10} shown in in the following table. There is no secondary standard for CO. The secondary NAAQS were established to protect general public welfare and the environment. The secondary NAAQS for NO_2, $PM_{2.5}$, and PM_{10} are either identical to or less stringent than the primary NAAQS for the same averaging interval.

Accordingly, compliance with primary NAAQS shown earlier in this report, by modeling of either SIL or NAAQS, demonstrates compliance with secondary NAAQS.

Secondary NAAQS Thresholds

Pollutant	Modeling Design Basis	NAAQS Threshold (µg/m^3)
NO_2	Maximum annual average over each of 5 years modeled	100 (53 ppb)
$PM_{2.5}$	24-hour average concentration 98th percentile average at each receptor over 5 years modeled	35
	Annual average, averaged over 5 years	15
PM_{10}	24-hour average concentration high-6th high (H6H) at each receptor over 5 years modeled	150

In general, modeled impacts below the secondary NAAQS indicate no adverse impacts on soils and vegetation. No sensitive aspects of the soil and vegetation in this area have been identified. Since modeling results demonstrate compliance with secondary standards it is anticipated that the potential impacts to the soil and vegetation will be negligible.

Based upon the results, it is concluded that the construction of the proposed project will not have a significant adverse impact on the surrounding soil and vegetation.

Visibility Impairment Analysis

The Class II visibility analysis requirements and results are presented in this section. Class II visibility impacts from the project were assessed with the VISCREEN model. AQD guidance was used in conjunction with EPA's *Workbook for Plume Visual Impact Screening and Analysis* (EPA 1992) to assess visibility impacts. Figure 9 from EPA's *Workbook* demonstrates that the background visual range to be used in the modeling for Tulsa, Oklahoma is 40 km.

AQD's guidance for determining visibility impacts in a Class II area allows the screening levels to be three times the Class I screening levels. This means that the relative sensitivity, ΔE, value of 6.0 and an absolute green contrast value of 0.15 were used.

A range of source-observer distances was evaluated, and the results were compared to the appropriate screening thresholds. This analysis included near-field locations within the Class II area, especially at any sensitive areas within 40 km. No areas within that distance were identified at this time. As a result, 40 km was the distance used for the source to observer and source to nearest Class I area boundary.

Modeling Results for Visibility Impacts

Background	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Critical	Plume	Critical	Plume
Sky	10	55	35.8	114	6	1.654	0.15	0.001
Sky	140	55	35.8	114	6	0.599	0.15	-0.010
Terrain	10	0	1.0	168	6	0.889	0.15	0.009
Terrain	140	0	1.0	168	6	0.263	0.15	0.009

None of the critical levels, or thresholds, were exceeded by the plume, or impacts at a distance of 40 km.

IX. INSIGNIFICANT ACTIVITIES

The insignificant activities identified and justified on Part 1b of the forms in the application and duplicated below were confirmed by the initial operating permit inspection. Records are available that confirm the insignificance of the activities. Appropriate recordkeeping is required for those activities indicated below with an asterisk. HFTR has included some activities that are not present at the refinery but that may be required in the future. For instance, wood chipping is not currently performed but could be required on a temporary basis in the event that a tornado destroyed large numbers of trees on refinery property.

Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTUH heat input (commercial natural gas).

Emissions from gas turbines with less than 215 KW rating of electric output.

*Storage tanks with less than or equal to 10,000 gallons capacity that store volatile organic liquids with a true vapor pressure less than or equal to 1.0 psia at maximum storage temperature.

Gasoline, diesel fuel, aircraft fuel, and fuel oil handling facilities, equipment and storage tanks except those subject to NSPS and standards in OAC 252:100-37-15, 39-30, 39-41, and 39-48, or with a capacity greater than 400 gallons.

*Emissions from storage tanks constructed with a capacity less than 39,894 gallons that store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature.

Additions or upgrades of instrumentation or control systems that result in emissions increases less than the pollutant quantities specified in OAC 252:100-8-3(e)(1).

Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes. Any welding or soldering is for maintenance purposes only, and is thus a Trivial activity.

Wood chipping operations not associated with the primary process operation.

Torch cutting and welding of under 200,000 tons of steel fabricated. Any such activity is for maintenance purposes only, and is thus a Trivial activity.

Site restoration and/or bioremediation activities of less than 5 years duration.

Hydrocarbon contaminated soil aeration pads utilized for soils excavated at the facility only.

Emissions from the operation of groundwater remediation wells including but not limited to emissions from venting, pumping, and collecting activities subject to *de minimis* limits for air toxics (OAC 252:100-42) and HAP (§112(b) of CAAA ’90).

*Non-commercial water washing operations (less than 2,250 barrels per year) and drum crushing operations of empty barrels less than or equal to 55 gallons with less than three percent by volume of residual material.

Hazardous waste and hazardous materials drum staging areas.

Sanitary sewage collection and treatment facilities other than incinerators and POTW. Stacks or vents for sanitary sewer plumbing traps are also included (i.e., lift station).

Emissions from landfills and land farms unless otherwise regulated by an applicable state or federal regulation.

Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas.

The applicant listed numerous activities in its application for the initial TV permit. Some were dismissed as Trivial and some could not be Insignificant because they were subject to various rules and regulations. The non-trivial activities are listed below, but with descriptions of their applicability that are much shorter than that given in the initial Memorandum. Headings are repeated as offered in the original application.

Laboratory
Applicant estimates emission of VOC from laboratory vent hoods to be well below 5 TPY.

Maintenance: Equipment and Piping
Maintenance of lines, pipes, and valves with the emission of VOC may be considered Insignificant only if the VOC emissions result from external cleaning or coating of the equipment. Maintenance associated in any way with the LDAR program is a regulated activity and cannot be Insignificant.

Maintenance: Miscellaneous
Parts cleaning with the emission of VOC. Appendix I allows "Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas" as an Insignificant activity. OAC 252:100-39-42 controls the design and operation of both cold (§a) and vapor (§b and §c) degreasers in Tulsa County. Further, degreasers may be subject to NESHAP MACT Subpart T. Degreasers affected by these state or federal requirements cannot be considered Insignificant activities.

Operations: Miscellaneous
Backup fuel fired pumps, compressors, or other machines with the emission of SO_X, NO_X, CO, CO_2, VOC, and particulates. Such equipment is included in Appendix I and may require record-keeping.

The loading, unloading, and screening of catalyst and/or support materials with the emission of particulates. Some catalyst may be toxic, with the potential to cause harm. Therefore, DEQ agrees that this should be included as an Insignificant activity and requires that records be maintained for each such transfer and screening event. Such records shall include the type and amount of material handled, applicant's engineering estimate of losses, and the method of calculation.

X. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations listed in OAC 252:100, Appendix Q. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Subchapter 3 enumerates the primary and secondary ambient air quality standards and the significant deterioration increments. At this time, all of Oklahoma is in "attainment" of these standards.

OAC 252:100-5 (Registration, Emissions Inventory and Annual Operating Fees) [Applicable]
Subchapter 5 requires sources of air contaminants to register with Air Quality, file emission inventories annually, and pay annual operating fees based upon total annual emissions of regulated pollutants. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility that result in emissions not authorized in the permit and that exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities refer to those individual emission units either listed in Appendix I or whose actual calendar year emissions do not exceed the following limits.

- 5 TPY of any one criteria pollutant
- 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAP or 20% of any threshold less than 10 TPY for a HAP that the EPA may establish by rule

Emission limitations and operational requirements necessary to assure compliance with all other applicable requirements for all sources are taken from the permit application, TV permit, from the various modifications based on the initial TV permit, from the TVR and construction permit applications, Civil Action No. 08-CV 020-D, or are developed from the applicable requirement.

OAC 252:100-9 (Excess Emissions Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for mitigation, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter (PM)) [Applicable]
Section 19-4 regulates emissions of PM from new and existing fuel-burning equipment, with emission limits based on maximum design heat input rating. Appendix C specifies PM emission limitations for all equipment at this facility. Fuel-burning equipment is defined in OAC 252:100-19 as any internal combustion engine or gas turbine, or other combustion device used to convert the combustion of fuel into usable energy. The flares of EUG-12 are not pieces of fuel-burning equipment under the state definition and are not affected by this rule.

All fuel-burning equipment uses gaseous fuel. AP-42 (7/98) Table 1.4-2 lists natural gas total PM emissions to be 7.6 lbs/million scf or about 0.0076 lbs/MMBTU, which is in compliance. The following equipment is subject to the requirements of this subchapter.

Equipment	Maximum Heat Input (MMBTUH)	Emissions (Lbs/MMBTU)	
		Appendix C	Potential Rate
Boilers 1, 2, 3, 4	233 each	0.28	0.008
ECDU atmospheric heater	380	0.25	0.008
CDU vacuum heater	100	0.36	0.008
FCCU B-2 heater	165	0.32	0.008
FCCU B-1 heater	38.4	0.44	0.008
Unifiner H-1 heater	42	0.43	0.008
TGTU #2	12.1	0.58	0.008
SCAN charge heater	25.2	0.48	0.008
NHDS charge heater	39	0.44	0.008
NHDS stripper/reboiler	44.2	0.42	0.008
CCR interheater #1	155	0.32	0.008
DHTU charge heater	80	0.37	0.008
CCR charge heater	120	0.33	0.008
CCR interheater #2-1	101	0.35	0.008
CCR interheater #2-2	25	0.48	0.008
CCR stabilizer/reboiler	85	0.36	0.008

Equipment	Maximum Heat Input (MMBTUH)	Emissions (Lbs/MMBTU)	
		Appendix C	Potential Rate
Naphtha Splitter Reboiler	100	0.30	0.008
CCR Helper Heater	25	0.48	0.008
Naphtha HDS Helper Heater	10	0.60	0.008
Diesel Hydro Helper Heater	45	0.42	0.008
007-J-26G	0.6	0.6	0.01
008-PA-50	0.6	0.6	0.01
050-G-1M	0.53	0.6	0.01
004-G-1	0.83	0.6	0.01
012-G-1M	3.37	0.6	0.01
045-G-1M	2.88	0.6	0.01
006-PE-80M	0.36	0.6	0.01
009-PE-143	5.6	0.6	0.09
009-PE-144	1.73	0.6	0.28
033-EG-5320	5.6	0.6	0.09
009-PE-152	3.04	0.6	0.03

Subchapter 19 also limits PM emissions from various processes which are both process and fuel-burning equipment. Limitations are specified based on process weight rate. The process weight at the FCCU is the sum of the catalyst circulation rate (up to 960 TPH) plus the gas oil charge rate. Assuming a specific gravity of 1.05 and a feed rate up to 1,000 BPH, a gas oil feed rate of 184 TPH is calculated for a total process weight rate of 1,144 TPH. The following table shows the process weight rates, allowable PM emissions rates, and permit limitations. The anticipated PM emissions rate from the FCCU is in compliance with Subchapter 19.

COMPARISON OF PM EMISSION RATES TO ALLOWABLE EMISSION RATES UNDER OAC 252:100-19

Process Unit	Process Weight, TPH	OAC 252:100 -19 Allowable PM Emissions, lb/hr	PM Emissions, lb/hr
FCCU	1,144	79.3	17

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences that consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. The flares are potential sources of visible emissions at this facility. Proper operation of the smokeless flares should maintain compliance.

Subsection 25-5(a) requires continuous monitoring of opacity at the FCCU catalyst regenerator. The unit is subject to the opacity standard of NSPS Subpart J. According to §25-5(c), sources required to comply with an opacity standard are exempt from §25-5(a), thus the regenerator is no longer subject to Subchapter 25. This subsection also applies to fossil-fueled steam generators with heat input greater than 250 MMBTUH. None of the refinery equipment meets this threshold.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Heavy traffic areas, including the racks and the offices, are paved. Vehicular traffic in the unpaved areas is greatly restricted for safety reasons. Under normal operating conditions, this facility will not cause fugitive dust problems; therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of H_2S emissions from any new or existing source to 0.2 ppm at standard conditions, based on a 24-hour average. Air dispersion modeling has been conducted showing maximum H_2S impacts from the refinery are in compliance with Part 2.
Part 5 covers new equipment standards. In particular, section 31-25 addresses sulfur oxides. New gas fuel-burning equipment, such as the process heaters of EUG 25 and EUG 29 or the modified process heaters of EUG 9 and EUG 26, must meet a standard of 0.2 lbs of SO_2 per MMBTU, three-hour average, per §25(a)(1). Because a permit condition limits H_2S content of the RFG to 0.1 gr/dscm, stoichiometric conversion of all H_2S to SO_2 would yield emissions of 0.027 lbs/MMBTU, well within the limit set forth. Emission monitoring, fuel monitoring, and recordkeeping standards are set in §25(c)(2), but apply to only those items rated at 250 MMBTUH or greater.
Paragraph 31-26(a)(1) covers hydrogen sulfide, setting requirements on the removal efficiency and emission rates for H_2S. The new process units added by the two construction projects mentioned above must meet this standard. All streams containing H_2S are routed to the SRU, whose efficiency at H_2S conversion meets the standard set in §26(a)(1). Using John Zink Company's estimate of incinerator performance (scaled to the expected 25 LTD throughput) yields 0.14 lbs/hr of H_2S emissions. Noting that H_2S input to the incinerator is 82.7 lbs/hr, the efficiency is calculated to be 99.8%, well above the 95% minimum requirement of this section. An emission rate of 0.14 lbs/hr is sufficient to qualify the unit for exemption from the efficiency criterion, because it is well below the 0.3 lbs/hr threshold value. The owner or operator shall install, maintain, and operate an alarm system that will signal a malfunction for all thermal devices used to control H_2S emissions from petroleum and natural gas processing facilities regulated under this subparagraph.
Paragraph 31-26(a)(2) covers SO_2 recovery standards for the SRUs. Specifically, the two SRUs, rated at 25 LTD, are covered by the standard described in subparagraph D. The SO_2 reduction efficiency requirement for any SRU is defined by the equation $Z = 92.34 \times X^{0.00774}$, where Z is the required efficiency and X is the throughput in LTD. For these SRUs, the result is 94.7%. According to the analysis performed for SRU #1 in Permit No. 98-021-C (M-16), the average emissions of SO_2 are slightly less than 8 lbs/hr. Converting 25 LTD of sulfur to SO_2 equivalent yields an input of 4,667 lbs/hr. The calculated efficiency for SRU #1 is 99.8%, well above the

94.7% threshold. A similar calculation for SRU #2 uses the expected emission rate of 5.6 lbs/hr of SO_2 supplied in the permit application to calculate an efficiency of 99.8%. This number is also well above the acceptable minimum value. Finally, note that both SRUs have emissions of SO_2 well below the 100 lbs/hr threshold necessary to qualify for exemption from the efficiency criteria. Thus, § 31-26(2) is not applicable.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits new gas-fired and liquid-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to emissions of 0.20 and 0.30 lbs of NO_X per MMBTU, three-hour average, respectively. Most fuel-burning equipment was installed prior to the effective date of this rule, has not been altered, replaced, or rebuilt in a manner increasing emissions, and is not subject. The CCR #1 Interheater of EUG 26 is rated at 155 MMBTUH and fits this subchapter's definition of "new." It has a federally-enforceable limit of 0.05 lb/MMBTU. The Naphtha Splitter Reboiler, also in EUG 26, has a limit of 0.03 lb/MMBTU. The ECDU Heater in EUG 33 has a limit of 0.04 lb/MMBTU. The heaters of EUG 27 have accepted federally-enforceable limits on NO_X emissions, but modifications performed on them, such as low-NO_X burners, did not have the effect of increasing NO_X emissions, so they are not affected by this subchapter. Similarly, the replacement B-2 heater in EUG 26 has lower emissions that the older unit which it replaced. EUG 27 heaters with input rating greater than 50 MMBTUH are shown in the following table with the limits they have accepted. All of the proposed new heaters at the East Refinery, other than B-2 and the Naphtha Splitter Reboiler, are smaller than 50 MMBTUH. The CDU Atmospheric Tower Heater will have a decrease in NOx emissions from installation of ULN burners, therefore, will not be "modified" and will not become subject to "new" standards.

Heater	MMBTUH Input	Limit Accepted
DHTU Reactor Charge	80	0.05 lbs/MMBTU
CCR Charge	120	0.05 lbs/MMBTU
CCR #2-1 Interheater	101	0.20 lbs/MMBTU
CCR Stabilizer/Reboiler	85	0.05 lbs/MMBTU
Naphtha Splitter Reboiler Heater	100	0.03 lbs/MMBTU
ECDU Heater	380	0.04 lbs/MMBTU

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
The catalytic cracking unit and catalytic reforming unit are existing sources, but are not subject to the standards of Subsection 35-2(a) because Tulsa County is not a non-attainment area for carbon monoxide. If sufficient modifications were performed to either unit that they might become affected sources, they would meet the new source standards of § 35-2(b) because both have complete secondary combustion systems. The applicant does not expect CO emissions from the FCCU to increase due to the secondary combustion, and has monitoring sufficient to show that post-project CO emissions do not exceed pre-project CO emissions. The FCCU has a monitor to establish that excess oxygen is present in the flue gas. The CRU uses a portable analyzer that establishes that excess oxygen is present at various points in the system. This monitoring is not an OAC 252:100 requirement, and would become so only under the reconstruction or modification situation outlined above. Conversion of the CRU to a CCR under the Low Sulfur Diesel Project covered by Permit No. 98-021-C (M-26) was not sufficient to

make this a "new" source, but it meets the new source standards of § 35-2(b) because compliance with the standards of 40 CFR Part 63 Subpart UUU satisfies the requirements of this subchapter.

OAC 252:100-37 (Volatile Organic Compounds) [Parts 3 & 7 Applicable]

Part 3 concerns the control of volatile organic compounds.

Subsection 37-15 (a) requires that all storage tanks with capacity greater than 40,000 gallons and storing a VOC with a vapor pressure greater than 1.5 psia shall be pressure vessels or shall be equipped with one of the following vapor-loss control devices.

(1) They shall be of EFR or fixed roof with IFR design, with the roof floating on the liquid surface at all times and equipped with a closure seal between the roof edge and the tank wall. Floating roofs are not suitable control for liquids with vapor pressure greater than 11.1 psia. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(2) They shall have an 85% efficient vapor recovery system and a vapor disposal system. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place.

(3) They shall have other equipment or methods with efficiency at least equal to those devices listed above.

Many of the tanks in EUG 3 have capacities greater than 40,000 gallons, but none of them stores liquid with vapor pressure greater than or equal to 1.5 psia. All of these tanks are exempt from the provisions of Section 37-15 per §37-4(a).

Tanks in EUG 4 are of various design and are subject to the overlap provisions of MACT CC. All are exempt from the provisions of §37-15 per §37-4(a) or §37-15(c).

Tanks in EUG 13 are smaller than 40,000 gallons. Note that the tanks in EUG 13 are subject to MACT Subpart EEEE.

Tanks in EUG 18 are smaller than 40,000 gallons. Note that the tanks in EUG 18 are subject to MACT Subpart GGGGG.

The tanks of EUG 20 have capacities greater than 40,000 gallons and are EFR tanks subject to NSPS Subpart Kb. They are exempt from the provisions of Section 37-15 per §37-15(c).

All of the tanks in EUG 21 and EUG 22 have capacities greater than 40,000 gallons and store liquids with vapor pressures greater than 1.5 psia. All of these tanks are pressure vessels and satisfy the requirements of §37-15(a).

The wastewater tanks of EUG 23 have organic vapor pressures below 1.5 psia, therefore, are not subject to standards of Subchapter 37.

Subsection 37-15 (b) requires storage tanks with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system per §37-15(a)(2). All of the tanks identified in the discussion of Subsection 15(a) satisfy the submerged fill condition. Tank #419 is listed as an Insignificant Activity. It has capacity less than 40,000 gallons but greater than 400 gallons and stores gasoline, whose vapor pressure exceeds 1.5 psia. It has submerged fill and satisfies the requirements of this section.

Tanks in EUG 18 satisfy the requirements of MACT Subpart GGGGG, which are more stringent than the requirements of §37-15.

Section 37-16 establishes standards for the loading of volatile organic compounds. Loading racks in EUG 14, including black oil railcar loading, black oil truck loading, diesel railcar loading and gas oil truck loading all involve material with vapor pressure well below 1.5 psia, and are exempt from the provisions of this section per §37-4(a).
Subsection 37-16 (a) contains requirements for loading facilities with throughput greater than 40,000 gallons per day. These conditions include a vapor collection and disposal system unless all trucks or trailers are bottom-loaded with hatches closed. Additionally, no drainage is allowed from the loading device after disconnection. The racks of EUG 15, including butane truck loading and propylene railcar and truck loading, and propane truck loading all have throughput capability of 40,000 gallons per day. Each of these processes is bottom-loading with hatches closed and all connectors shut automatically or are drained before disconnection. Although Subsection 37-16 (c) does not specifically exempt sources subject to MACT Subpart CC, it does exempt those subject to MACT Subpart R or NSPS Subpart XX. The rack is subject to MACT Subpart CC, which specifically requires compliance with the standards of MACT Subpart R. The HSR rack does not load trucks or railcars, so it is not subject to §16(a).
Part 5 limits the VOC content of coating or other operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is not an affected operation.
Part 7 regulates specific processes.
Section 37-36 requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize emissions. The flares of EUG 12 are not considered to be fuel-burning equipment but may be considered to be "refuse burning equipment." The boilers of EUG 8, the process heaters of EUGs 9, 25, 26, 27, 29, and 33 and the TGTUs of EUG 10 are affected sources. Proper maintenance and operation to provide essentially complete combustion provide compliance.
Section 37-37 concerns water separators that receive water containing more than 200 gallons per day of VOC. The only equipment that may be affected by this section are the "API separators" at the WWTP and Tank 475 of EUG 20, designed for storage of off-test water at the WWTP. These EFR tanks are subject to NSPS Subpart Kb and compliance with the requirements of 40 CFR § 60.112b(a)(2) satisfies the requirements of OAC 252:100-37-37(2). However, the section is not applicable to either of these situations because testing of the effluent has shown it to involve material with vapor pressure well below 1.5 psia, leaving both exempt from the provisions of this section per §37-4(a). The wastewater tanks of EUG 23 store oily wastewater but are not operated to perform oil-water separation.

OAC 252:100-39 (VOC in Non-attainment Areas) [Applicable]
Part 3 affects petroleum refinery operations.
Section 39-15 concerns petroleum refinery equipment leaks and is frequently referred to as LDAR, for Leak Detection and Reporting. It applies to all components that might have leaks of VOC when tested by EPA Reference Method (RM) 21 as found in the NSPS regulations of 40 CFR Part 60. For the purposes of this section, VOC with vapor pressure less than 0.0435 psia is exempt. Standards and operating procedures are set out in §39-15(c), as summarized following.

1) Monitor per Subsection (f), record leaking components and tag each component. Repair and retest leaking components and identify those that cannot be repaired until turnaround. Seal all lines ending with a valve with a second valve, flange, plug, or cap.

2) AQD may require remedial action based on the number and severity of tagged components awaiting repair.

3) Pipeline and pressure relief valves shall be marked in a manner obvious to both monitoring and DEQ personnel.

Monitoring requirements are found in §39-15(f), as summarized following.

1) Monitoring shall consist of annual RM 21 testing for pump seals, pipeline valves in liquid service, and drains, quarterly RM 21 testing for compressor seals and for pipeline valves and pressure relief valves in gas service, and weekly visual monitoring for all pump seals. Further, monitoring shall occur within 24 hours for any pump seal from which VOC liquids are observed dripping and for any relief valve that has vented to the atmosphere. Any leaking component shall be monitored immediately after repair.

2) Vapor recovery devices, inaccessible valves, storage tank valves, valves not externally regulated, and pressure relief devices connected to a flare header are exempt from (1) provided that inaccessible valves will be monitored during turnarounds.

3) Any leaking component not immediately repaired shall have a readily visible dated identifying tag attached until it is repaired.

Record keeping and reporting requirements are identified in §39-15(g) and (h), and will be more fully enumerated in the Specific Conditions of the permit. The facility states that it is in compliance with all of the requirements listed above.

<u>Section 39-16</u> concerns petroleum refinery process unit turnarounds and outlines procedures to be used during the planned shutdown, inspection, repair, and restart of a unit. VOC in the unit shall be routed to a flare or vapor recovery system until the unit is blown down to pressure compatible with the control device pressure. The system may then be purged using appropriate materials. The unit may not be vented to atmosphere until unit pressure is less than 5 psig. VOC may not be emitted to the atmosphere through any control device unless it is burned in a smokeless flare or equivalent device, except for special circumstances. Written notice of the unit to be shut down, the date of shut down and the amount of VOC emissions anticipated shall be provided to AQD at least 15 days in advance. Scheduled turnarounds may be exempted from the control requirements during non-oxidant season if the required notice makes a specific request to that effect. The facility has provided the appropriate notices for past turnarounds and is in compliance.

<u>Section 39-17</u> concerns non-condensable VOC emitted from equipment used in producing vacuums. Only the vacuum tower at the CDU is affected by this section.

<u>Subsection 39-17(b)</u> requires that non-condensable VOC from steam ejectors with barometric condensers, steam ejectors with surface condensers, and mechanical vacuum pumps shall be incinerated or reduced by 90% through other means. As mentioned in the Process Description, the vacuum tower has steam ejectors with surface condensers. Vacuum tower overhead enters a four-stage ejector system. Discharge from the first three ejectors is sent to water-cooled surface condensers. Under normal operations, discharge from the fourth ejector is sent to the FCCU "wet gas" compressor known as J-50. That gas is then treated at the FCCU amine treater and sent to RFG. In the event that J-50 is not operating, gas from the fourth ejector is vented into the flare system.

Subsection 39-17(c) requires that non-condensable VOC from hotwells and accumulators shall be incinerated and that these pieces of equipment shall be covered. Hotwells are associated with barometric condensers, of which there are none. Vacuum tower overhead condensate from the surface condensers discussed above flows to a pressure vessel (FA-30) that is an accumulator. Any additional vapor from this system is handled with the non-condensable vapors emitted from the fourth ejector, as described above. Subsection 17(c) also requires that the presence of a pilot flame be monitored by any of several means. Heaters at the CDU, as well as those facility heaters using RFG, have pilot flame sensors.

Section 39-18 concerns refinery effluent water separators. The only equipment that may be affected by this section are the "API separators" at the WWTP and Tank 475 of EUG 20, designed for storage of off-test water at the WWTP and authorized by Permit No. 96-227-O. The section is not applicable to either of these situations because testing of the effluent has shown it to involve material with vapor pressure well below 1.5 psia, leaving both exempt from the provisions of this section per §39-4.

Part 5 concerns petroleum processing and storage.

Section 39-30 affects petroleum liquid storage in external floating roof EFR tanks of capacity greater than 40,000 gallons located in Tulsa County. While the facility contains numerous tanks fitting this description, each tank is subject to an NSPS subpart and/or to MACT Subpart CC. Tanks subject to NSPS Subparts K, Ka, or Kb, are exempt from this section per §39-30(b)(3). Tanks subject to NESHAP MACT Subpart CC are exempt from this section per §39-30(b)(4). Thus, all tanks potentially subject to §39-30 are exempt.

Part 7 contains rules affecting specific processes.

Subsections 39-41(a) & (b) extend the "new" tank requirements of OAC 252:100-37-15 to existing tanks that store gasoline or other organic materials with vapor pressure greater than 1.5 psia. See the 37-15 discussion above. This facility meets these requirements.

Subsection 39-41(c) contains provisions concerning loading of VOC. NESHAP 40 CFR Part 63 Subpart CC had an effective date of August 18, 1998, for the gasoline loading facility. This MACT Standard references both NESHAP MACT Subpart R and NSPS Subpart XX. Because these subparts impose conditions at least as stringent as this paragraph, and because the facility is in compliance with Subpart CC, the current requirements should be satisfied. The other organic compounds loaded from the units in EUG 15 (propylene and butane) are subject to this subsection, and are conducted in pressurized systems which prevents discharge of VOC from the transports being loaded.

Subsection 39-41(e) contains provisions pertinent only in Tulsa County. Storage system requirements are extended to gasoline or VOC storage tanks with capacities between 2,000 and 40,000 gallons. No tanks at this facility meet these criteria. It also requires that the stationary loading facility be checked annually using EPA Method 21. Leaks greater than 5,000 ppmv shall be repaired within 15 days. The facility appears to be in compliance. Finally, there are additional controls with respect to transport vessels. The vessels must be maintained vapor tight and must be capable of receiving and storing vapors for ultimate delivery to a vapor recovery/disposal system. Any defect that impairs vapor tightness must be repaired within five days. Certification of vapor tightness and of repairs must be provided and no vessel shall be loaded without demonstrating the proper certification. DEQ may perform inspections of vapor tightness and may require owner/operators to make necessary repairs. This facility and the transports loading there have been in compliance.

Section 39-42 concerns metal degreasing. Subsections (b) and (c) cover vapor type and conveyorized degreasing, neither of which is present at this facility. Section (a) covers cold cleaning units, requiring a cover on the unit that can be easily operated with one hand, an internal drain board that allows the cover to close if practical; if not practical, provide external drainage, and that a conspicuous label summarizing proper operation be attached to each such unit. The operating standards for the label are enumerated in Paragraph (a)(2).

OAC 252:100-40 (Friable Asbestos During Demolition & Renovation Operations) [Applicable]
Section 40-5 describes additional procedures for the proper handling of asbestos. These procedures are detailed in the Specific Conditions.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Quality Rules are not applicable to this facility.

OAC 252:100-11	Alternative Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Feed & Grain Facility	not in source category
OAC 252:100-47	Municipal Solid Waste Landfills	not in source category

XI. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]

Emissions of several regulated pollutants exceed the major source level of 100 TPY for a listed source. PSD will apply to any future project whose added emissions exceed the significance levels: CO 100 TPY, NO_X 40 TPY, SO_2 40 TPY, $PM_{2.5}$ 10 TPY, PM_{10} 15 TPY, VOC 40 TPY, or GHG 75,000 TPY.

NSPS, 40 CFR Part 60

[Subparts J, Ja, K, Kb, UU, GGG, GGGa, QQQ, IIII, and JJJJ are Applicable]

Subparts D, Da, Db, Dc (Steam Generating Units)

These subparts apply to steam generating units of various sizes constructed, modified, or reconstructed after various dates. Common to the definition of all affected facilities is the requirement that these devices combust fuel, which would exclude the use of waste heat used in heat exchangers to produce steam. Subpart Dc expands the definition slightly to include the heating of a heat transfer medium, but explicitly excludes process heaters from being affected facilities. Generation of steam at HFTR occurs at the boiler house (BoHo) or in the heat exchangers, so only the BoHo is capable of being an affected facility. All four boilers were constructed in the 1950s, well before August 17, 1971, the earliest effective date of any of these subparts. Any work performed on these boilers since 1971 has been insufficient to meet the modification or reconstruction standards. Add-on controls required by enforcement settlements do not constitute modification or reconstruction.

Subpart J (Petroleum Refineries)

Fluid catalytic cracking unit (FCCU) catalyst regenerators, fuel gas combustion devices (FGD), and Claus sulfur recovery plants except Claus plants producing less than 20 long tons per day are all affected facilities under this subpart. Flares may be considered to be FGDs under specific circumstances and would thus be affected facilities. With certain exceptions, the effective date for all affected facilities is between June 11, 1973, and May 14, 2007. The FCCU and most FGDs were constructed in 1949 or 1972, prior to the effective date. Although many changes have been made in the handling of waste heat, such as through the efficient use of heat exchangers, most FGDs remain unmodified. SRU #1 was constructed in 1972 and produces 15 long tons per day. Most work performed on the FCCU or FGDs since 1973 has been insufficient to meet the modification or construction standards. However, construction work for the SCAN and Low Sulfur Diesel projects authorized by Permits No. 98-021-C (M-16) and 98-021-C (M-26) has modified certain units and added other new units, all now subject to Subpart J. Both SRUs are now subject as are the heaters identified as CCR Stabilizer Reboiler, CCR #1 Interheater, SCAN Charge, NHDS Charge, and NHDS Stripper Reboiler. Under the terms of the CD 08CV 020-D, FGDs at the refinery are subject to the subpart, effective June 30, 2008 and December 31, 2010. Standards required for these equipment items may be found in Specific Conditions covering EUGs 8, 9, 10, 25, 26, and 27. The CD also states that the catalyst regenerator at the FCCU is an affected facility, but with staged compliance dates. Compliance with the CO standard was required on June 30, 2008, and compliance with the SO_2 and PM_{10} standards was December 31, 2009.

Subpart Ja (Petroleum Refineries)
On June 24, 2008, EPA promulgated standards for new, modified, or reconstructed affected facilities at petroleum refineries. The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCCU), delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants. Only those affected facilities that begin construction, modification, or reconstruction after May 14, 2007, are subject to this subpart.

Under 40 CFR § 60.100a(c)(1), adding any new piping from a process unit to a flare is explicitly considered a modification, making the flare subject to Subpart Ja flaring volume limits (250,000 SCF/day, 30-day rolling average) in 40 CFR § 60.102a(g)(3), the work practice standards of 40 CFR 60.103a, and performance testing requirements under 40 CFR § 60.8. Between the modifications which have occurred and which are proposed, all flares will be treated as being subject to Subpart Ja.

Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. The new heaters, EUG-29, the new Naphtha Splitter Reboiler Heater 10H-105, the FCCU Charge Heater B-2, and the modified CDU Atmospheric Tower Heater are considered fuel gas combustion devices which commenced construction after May 14, 2007, and are subject to the final standards promulgated in this subpart. Those heaters are subject to a limitation of sulfur in fuel of 162 ppm (3-hour average) and 60 ppm (annual average). The permit limitation is equal to the annual limit, therefore, more stringent.

Subpart Ja included NOx standards for units which are larger than 40 MMBTUH capacity. Two of the new heaters (Naphtha Splitter Reboiler and DHTU Helper Heater) are larger than the 40 MMBTUH threshold. The heaters are subject to a limitation of 0.04 lb/MMBTU NOx for natural draft units and 0.06 for forced draft units. Affected units larger than 100 MMBTUH are required to install CEMS. The CDU Atmospheric Tower Heater will have a decrease in NOx, therefore, was not modified and will not become subject to these standards. Heater B-2 has decreased NOx emissions from installation of low-NOx burners, therefore, does not become subject to Subpart Ja for NOx.

Subparts K, Ka, Kb (VOL Storage Vessels)
There are many tanks to consider. The earliest effective date of any of these subparts is June 11, 1973. All but ten of the hydrocarbon storage tanks were constructed before that date. They have not been modified or otherwise altered to sufficient extent to meet the reconstruction or modification criteria, and are not affected sources. Subpart Kb excludes vessels storing organic liquids with vapor pressures below 3.5 kPa (0.5 psia).

Subpart K
Tank #13 in EUG 4 has capacity greater than 65,000 gallons, was constructed in 1976, and is an affected source per 40 CFR § 60.110(c)(1). Standards contained in §112 require a floating roof for stored liquids with true vapor pressure (TVP) greater than 1.5 psia and a vapor recovery system for liquids with TVP greater than 11.1 psia. Tank #13 is of internal floating roof construction and does not contain liquids with TVP greater than 11.1 psia. Monitoring requirements are described in §113 and include recording the liquid stored, the period of storage, and the maximum TVP during the storage period.

Subpart Ka
None of the tanks was constructed after May 18, 1978, and before July 23, 1984, within the applicability window for Subpart Ka.

Subpart Kb
Tanks in EUG 20 were constructed after July 23, 1984. Tanks 476 and 478 meet these standards with external floating roofs (EFR) with primary and secondary seals, and satisfy the requirements of §112b(a)(2)(i - iii).
The facility is permitted to add tanks whose VOC emissions do not exceed a cap. It is presumed these new tanks will all be subject to Subpart Kb.

Subpart GG (Stationary Gas Turbines)
There are no gas turbines at this facility.

Subpart UU (Asphalt Processing and Asphalt Roofing Manufacture)
Affected facilities at refineries are each asphalt storage tank and asphalt blowing still. HFTR has no blowing stills. The storage tanks have been moved to the HEP permit except for the tanks in EUG-3, which will be shown in the permit as being subject to Subpart UU.

Subparts VV and VVa (VOC Leaks in SOCMI)
Several subparts of NSPS make reference to Subpart VV, but these references do not make equipment items or processes directly subject to Subparts VV or VVa. Propylene, a product listed in these subparts, is manufactured by the refinery. Regardless of the preceding comments, it has been determined that the refinery is currently subject only to Subpart GGG or GGGa, which are discussed below.

Subpart XX (Bulk Gasoline Terminals)
This subpart applies to loading racks at bulk gasoline terminals for which construction or modification commenced after December 17, 1980. The gasoline loading terminal has been moved to another permit.

Subpart GGG (VOC Equipment Leaks in Petroleum Refineries)
A compressor is an affected facility and the group of all equipment within a process is an affected facility. The word "equipment" in the preceding sentence is defined in 40 CFR § 60.591 to mean each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. Any affected facility that commences construction or modification after January 4, 1983, and before November 7, 2006, is subject to the requirements of this subpart. Much of the refinery was constructed or modified well before 1983, but numerous facilities listed in Section III: Equipment meet the applicability criteria used here. They are identified in the Specific Conditions, as necessary.

Subpart GGGa (VOC Equipment Leaks in Petroleum Refineries)
This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit, which commenced construction or modification after November 7, 2006, and which is located at a petroleum refinery. This subpart defines "process unit" as "components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates: a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." Subpart GGGa requires the leak detection, repair, and documentation procedures of NSPS, Subpart VVa. All affected equipment which commenced construction or modification after November 7, 2006, in VOC service is subject to this subpart, including the modified CCR, DHTU, and the Naphtha Splitter Unit. This project will include construction of the new LPG, and Naphtha Fractionation Column units, and modification of the CCR, DHTU, NHDS, and ALKY Units. All applicable requirements have been incorporated into the permit.

Subpart KKK (VOC Equipment Leaks / Onshore Natural Gas Processing Plants)
No natural gas processing occurs at this facility.

Subpart LLL (Onshore Natural Gas Processing: SO_2 Emissions)
No natural gas processing occurs at this facility.

Subpart QQQ (VOC from Petroleum Refinery Wastewater Systems)
Affected facilities include each individual drain system, each oil-water separator, and each aggregate facility, where aggregate facility is the subject of further definition. Facilities constructed, modified, or reconstructed after May 4, 1987, are subject to the requirements of this subpart. Many of the facilities in the refinery were built before the effective date and are not subject. Construction of the SCAN and Low Sulfur Diesel projects under Permits No. 98-021-C (M-16) and 98-021-C (M-26) created several drain systems potentially subject to Subpart QQQ. These systems include all drains at SCAN, NHDS, and SRU #2. New drains installed during modification of the HTU to DHTU and modification of the CRU to CCR are also affected. Systems are grouped as Group 1 or Group 2 under Refinery MACT Subpart CC (q.v.), where Group 1 members are those emission points to which control criteria apply. Under this division, Group 1 activities are subject to the standards of MACT Subpart CC, while Group 2 activities are subject to QQQ, if they meet the applicability criteria. An Applicability Determination issued June 11, 2007, by George Czerniak of EPA, indicates that if a facility identifies a Group 2 system as Group 1, and subjects it to the control standards of NESHAP Subpart FF, that system

is exempt from NSPS QQQ. All of the mentioned systems are exempt from QQQ, but they remain subject to MACT CC. Tanks subject to NSPS Subpart Kb are not subject to the standards of Subpart QQQ, but they are subject to overlap provisions in MACT Subpart CC. Specific Conditions address these overlaps. There will be new process drains in the new Naphtha Fractionation Column Unit, but by the overlap provisions of MACT Subpart CC, the new drains are subject only to the MACT.

Subpart IIII (Stationary Compression Ignition Internal Combustion Engines)
Subpart IIII affects stationary compression ignition (CI) internal combustion engines (ICE) based on power and displacement ratings, depending on date of construction, beginning with those constructed after July 11, 2005. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator. The emergency engines in EUG-35a are subject to emergency engine standards under Subpart IIII.

Subpart JJJJ (Stationary Spark Ignition Internal Combustion Engines (SI-ICE))
This subpart was published in the Federal Register on January 18, 2008. It promulgates emission standards for new SI engines ordered after June 12, 2006, and all SI engines modified or reconstructed after June 12, 2006, regardless of size. The emergency engines in EUG-34a are subject to emergency engine standards under Subpart JJJJ.

NESHAP, 40 CFR Part 61 [Subparts M and FF Applicable]
Of the pollutants listed in 40 CFR Part 61 (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride), only asbestos and benzene are emitted by this facility. Several subparts cover emissions of benzene but all product streams are less than the 10% threshold.
Subpart J (Equipment Leaks) The overhead from the reformate splitter will contain >10% benzene, but the facility is only required to comply with the MACT CC Equipment Leak provisions as described in the overlap provisions found in 40 CFR § 63.640(p).
Subpart L (Coke By-Product Recovery) This facility is not an affected source.
Subpart M (Asbestos) applies to this facility. HFTR is involved in the removal of asbestos and shall abide by the applicable requirements of §61.145.
Subpart Y (Benzene Storage Vessels) This facility is not an affected source.
Subpart BB (Benzene Transfer Operations) This facility is not an affected source.
Subpart FF (Benzene Waste Operations) This facility is a petroleum refinery and is an affected source per 40 CFR 61.340(a). Sections (b) and (c) contain requirements implying coverage by §§61.343 (Tanks), 61.344 (Surface impoundments), 61.345 (Containers), 61.346 (Individual drain systems), 61.347 (Oil-water separators), 61.348 (Treatment processes), and 61.349 (Closed-vent systems and control devices). Sections 61.350-352 cover alternative methods. Sections 61.354-6 concern monitoring, recording, and reporting benzene wastes, and contain a great amount of detail on these topics.

NESHAP, 40 CFR Part 63

[Subparts CC, UUU, EEEE, ZZZZ, DDDDD, and GGGGG Applicable]

<u>Subpart Q</u> (Industrial Process Cooling Towers)

This subpart applies only to cooling towers using chrome. None is used by the facility.

<u>Subpart R</u> (Gasoline Distribution Facilities)

The gasoline loading rack has been moved to the HEP permit.

<u>Subpart CC</u> (Petroleum Refineries)

Various process units and related emission points at petroleum refineries may be affected sources. They must be located at a plant site that is a major source per §112(a) of the Clean Air Act and they must emit or have equipment containing or contacting any of the organic HAP listed in Table 1 of the subpart. Table 1 contains only 28 chemicals, including meta-, ortho-, para-, and mixed isomers of both cresol and xylene. Organic HAP, as used in this subpart, refers only to chemicals on this list of 28. HFTR/HEP is an affected facility. Following are the source categories listed in 40 CFR § 63.640(c) and a summary of applicable requirements for each.

- (c)(1) Miscellaneous process vents from petroleum refining process units. Vents identified as Group 1 vents are those having VOC emissions of at least 33 kilograms (73 pounds) per day from existing sources or at least 6.8 kilograms (15 pounds) per day from new sources, both measured after any final recovery device, but before any control device or discharge to the atmosphere. The VOC emissions must have organic HAP concentrations of at least 20 ppmv. Either of two requirements described in §643 shall be used for these emissions; a flare that meets the standards of 40 CFR § 63.11(b), or a control device that reduces the organic HAP content by 98% by weight, or to 20 ppmv dry, corrected to 3% oxygen. If a boiler or process heater is used for the second option, the vent stream shall be introduced into the flame zone. With one exception, all process vents have been routed to one of the flares or to the refinery fuel gas (RFG) system. With the new flare gas recovery system, all but those large events caused by malfunction will be routed to RFG. Emissions routed to the RFG system are not affected sources, per §640(d)(5). Emissions from the surface condensers in the vacuum tower at the CDU are currently piped directly into the flame zone of the unit process heater, satisfying the requirements of §643(b) and obviating the need for monitoring per §644(a)(3).
- (c)(2) Storage vessels associated with petroleum refining process units. Group 1 storage vessels are required to comply with §§63.119 through 63.121 of Subpart G except as provided for in §63.646(b) through (l). Group 1 storage vessels for an existing source are those vessels with design capacity at least 177 m^3 (46,758 gallons), storing a liquid with a maximum true vapor pressure at least 10.4 kPa (1.5 psia) and annual average true vapor pressure at least 8.3 kPa (1.2 psia), and storing a liquid with an annual average organic HAP concentration greater than 4 percent by weight. Subpart G is the MACT for Process Vents, Storage Vessels, Transfer Operations, and Wastewater at Synthetic Organic Chemical Manufacturing Industries (SOCMI). Most of the exceptions are simply substitute language to properly identify references and terminology; any substantive exceptions will be identified in the Specific Conditions of this permit. The sections cited essentially repeat the language of NSPS Subpart Kb. The compliance date for new tanks is first operation, and the compliance date for all existing tanks was August 18, 2005.

On September 29, 2015, EPA issued its final Risk and Technology Review (RTR) for the Petroleum Refinery Sector, also known as the Refinery Sector Rule (RSR), which was proposed on June 30, 2014. The final rule was published in the Federal Register on December 1, 2015, with an effective date of ***February 1, 2016***. The final rule requires continuous fenceline monitoring for benzene and calls for a comprehensive program of process changes and pollution prevention targeted at reductions in visible flare emissions and releases by pressure release devices (PRDs). The new requirements also mandate additional reductions from storage tanks and delayed coker operations, some of which had no controls required previously, as well as new control requirements for maintenance activities and episodic releases that were previously unregulated.

Because of overlap provisions to conform treatment of storage vessels with other NSPS or NESHAP Subparts, each EUG containing storage vessels is addressed separately.

EUG 4 - Wastewater tanks. Overlap provisions with NSPS Subparts Kb and QQQ, NESHAP Subpart FF, and MACT CC, including references to MACT G, require demonstration of compliance with NSPS Subpart Kb to satisfy all requirements.

EUG 18 - MACT GGGGG tanks. None of these tanks is subject to MACT CC.

EUG 20 - EFR tanks subject to NSPS Subpart Kb. Compliance with Subpart Kb is sufficient.

- (c)(3) Wastewater streams and treatment operations associated with petroleum refining process units. A Group 1 wastewater stream is one with a total benzene load of at least 10 megagrams (Mg) per year (11 TPY), a flow of at least 0.02 liters per minute (0.32 gph), a benzene concentration of at least 10 ppm, and not exempt from the control requirements of NESHAP Subpart FF. HFTR's wastewater stream exceeds 10 Mg per year and is subject to NESHAP Subpart FF. Individual streams may be exempted from control requirements if they contain more than 10% water by volume, provided that the total benzene content of such exempted streams does not exceed 6 Mg per year. Exemptions of such streams must be demonstrated and documented.
- (c)(4) Equipment leaks from petroleum refining process units. The standards for all equipment are found in 40 CFR Part 60 Subpart VV, with certain minor exceptions. Among these are the necessary corrections to definitions of organic HAP as found in MACT CC and the requirement that all records be maintained for at least five years. Exceptions as to new sources, hydrogen service, and others are described in the Specific Conditions.
- (c)(5) Gasoline loading racks classified under SIC code 2911 shall comply with the standards of 40 CFR Part 63 Subpart R, with the only exception relating to the definition of organic HAP. The gasoline loading terminal has been moved to the Holly Energy Partners permit.
- (c)(6) Marine vessel loading operations. HFTR has none.
- (c)(7) Storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under SIC code 2911 contiguous to and under common control with a refinery. The gasoline loading terminal has been moved to the HEP permit.

- (c)(8) Heat exchange systems. Specifications for “Heat exchange system” have been added as 40 CFR § 63.654. A facility is exempt from these standards if a cooling tower operate with a pressure difference of at least 5 psia between the cooling water side and process side, or employ an intervening cooling fluid with is less than 5% organic HAPs. Otherwise, the operator must perform monitoring to identify leaks and repair those leaks. There are separate standards for closed-loop systems and once-through systems.
- (c)(9) Delayed coker decoking operations. Specifications for decoking operations have been added as 40 CFR § 63.657. Depressurization is required to be to a control device or back into the process.

Various sources are explicitly named in 40 CFR § 63.640(d) as not being affected sources, including the following.

- (d)(1) Storm water from segregated storm water sewers.
- (d)(2) Spills.
- (d)(3) Any pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve or instrumentation system that is intended to operate in organic HAP service less than 300 hours per year.
- (d)(4) Catalytic cracking unit and catalytic reformer catalyst regeneration vents and sulfur plant vents.
- (d)(5) Emission points routed to a fuel gas system, as defined in §641. No testing, monitoring, recordkeeping, or reporting is required for RFG systems or for emission points routed to RFG systems.

Subpart UUU (Petroleum Refineries – Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Plant Units)
The FCCU catalyst regeneration flue vent is subject to metal and organic HAP emissions standards described in §§1564 and 1565 of MACT UUU. Because the FCCU is not currently subject to NSPS Subpart J, the facility chooses to demonstrate compliance using Option 3 of Table 1, which requires that emissions of nickel not exceed 0.029 lbs/hour. Catalytic reforming unit vents, including those at the CCR, are subject to organic HAP emission limits during depressuring and purging events, which includes depressurization, purging, coke burn, catalyst rejuvenation, and reduction or activation purge. The requirements outlined in Table 15 of the MACT are satisfied by compliance with OAC 252:100-39-16, which contains procedures for such events; the MACT is currently complied with by depressurizing into the flare system. The requirements of Table 22 (Option 3 for the CCR) are met by monitoring HCl concentration. The SRUs are subject to NSPS Subpart J, compliance with which satisfies the requirements of MACT UUU.

Subpart EEEE (Organic Liquids Distribution (Non-gasoline))
Subpart EEEE concerns those organic HAP listed in Table 1 of the subpart and handling equipment, including storage tanks, transfer racks, equipment components, and transport vehicles while at the transfer racks. Criteria described in Table 2 of the subpart indicate that tanks with capacity less than 5,000 gallons are not affected. Except for the loading rack, all components of the Hydrocarbon recovery system (HRS) in EUG 18 are already covered under MACT CC, and are thus exempt from Subpart EEEE per 40 CFR §63.2338(c)(1). Because the rack is not subject to any of the emission limits in Table 2 of this subpart, it is not subject to any other standard except for initial notification under §63.2382(b)(2).

Subpart ZZZZ (Reciprocating Internal Combustion Engines (RICE))
Engines which are subject to NSPS Subparts IIII or JJJJ are required to comply with those subparts. Existing spark-ignition 4SRB engines and CI engines are required to comply with the following standards of Subpart ZZZZ:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	

Subpart DDDDD, (Industrial, Commercial and Institutional Boilers and Process Heaters at major sources of HAPs)
This regulation was re-promulgated on December 23, 2012. The RFG-fired heaters and boilers are subject to the following standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million BTU per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million BTU per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million BTU per hour, but greater than 5 million BTU per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in §63.7540.

Subpart GGGGG (Site Remediation)
Subpart GGGGG affects various equipment involved in site remediation that emit any of certain HAP identified in the subpart and that are located at sources that are major sources of HAP as defined in 40 CFR § 63.2. Process vents, remedial material management units (tanks), and equipment leaks are affected facilities under this subpart. EUG 18 (Hydrocarbon Recovery System) contains equipment affected by this MACT. Because of overlap provisions with other MACT subparts, compliance is satisfied through carbon canisters on the tanks.

CAM, 40 CFR Part 64 [Applicable]
Compliance Assurance Monitoring (CAM) as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source that is required to obtain a Title V permit, if it meets all of the following criteria.

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY

Although there have been very few emission limits for sources in the refinery, many sources within the refinery are subject to the standards of 40 CFR Part 63 Subpart CC or Subpart UUU. Provisions for monitoring contained in these subparts is considered presumptively acceptable monitoring in accordance with 40 CFR § 64.4(b)(4). The required explanation of the applicability is found in the discussion for MACTs CC and UUU.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
Naturally occurring hydrocarbon mixtures, prior to entry into a natural gas processing plant or a petroleum refining process unit, including condensate, crude oil, field gas, and produced water, are exempt for the purpose of determining whether more than a threshold quantity of a regulated substance is present at the stationary source. Listed materials produced and held for sale as fuel are also exempt. HFTR filed a Risk Management Plan with the EPA on June 21, 1999, and filed a revised and updated plan on June 21, 2004. EPA's file number is 1000 0014 6567.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

The Standard Conditions of the permit address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; §82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

XII. COMPLIANCE

Tier Classification and Public Review

This application has been classified as **Tier II** based on the request for a construction permit for a “significant” modification. The applicant published the “Notice of Filing Tier II Application” in *The Tulsa Business & Legal News* on September 29, 2019. A draft of this permit was also made available for public review for a period of 30 days as stated in another newspaper announcement in the Tulsa World on December 20, 2019, and on the Air Quality section of the DEQ web page at *http://www.deq.ok.gov*.” The applicant has requested concurrent public and EPA review. The draft/proposed permit was submitted to EPA for a 45-day review period. No comments were received from Region VI, but the following comment was received from the public (copied electronically exactly as submitted):

SYSTEM IDENTIFIER 159
Permit Number: 2017-1908-C (M-2) PSD

Comment:
I was chosen as 2019-2020 Fellow with the Alliance of Nurses for Healthy Environments which promotes “healthy people and healthy environments by educating and leading the nursing profession, advancing research, incorporating evidence-based practice, and influencing policy.” The Fellowship has a particular focus on environmental health equity and justice and addressing the disproportionate impact of environmental exposures on vulnerable groups. I have chosen to focus on the River West community because of it close proximity to Holly Frontier oil refinery, the Covanta Trash to Energy plant, the PSO Power Station and other nearby industries. In order to learn more about this community, I developed a survey of their perceptions of air quality. It was completed by 110 persons, who all with the exception of 13 people, live in the River West neighborhood. The 13 others reside in the neighborhood two blocks south of the Holly Frontier East Refinery. Some of the residents to the south report that Holly Frontier wants to buy them out but they are not satisfied with the price being offered. The results are very concerning. I hope that they will be further investigated

TULSA’S RIVER WEST AREA AIR QUALITY SURVEY

Alliance of Nurses for Healthy Environments Fellowship Project Conducted between October 5-December 7, 2019 Total number surveyed=110 Do you feel that there is a problem with air quality in your neighborhood? Yes N=88 (80%) No (If “NO”, proceed to questions 7-9. Question 10 is optional) N=22 (20%) QUESTIONS 2 THROUGH 6 ANSWERED BY 88 RESPONDENTS 1. In which of the following ways do you feel that you or any members of your household are affected by air quality? Check all that apply. Don’t like the way the air smells. (If checked, answer the next three questions.) N=72 (82%) Concerned about my health N= 50 (57%) Concerned about the health of members of my household N=46 (52%) Want to move to a different place N=42 (48%) Causes irritation to eyes/nose/throat N=38 (43%) Limit my children’s outdoor activities N= 31 (35%) Have difficulty in breathing/triggers asthma attack N=29 (33%) Personally avoid outdoor activities when possible N=28 (32%) Any other ways N=5 (6%) Leaves odors in my house (1), allergies (2) Headaches (1) Outdoor smoking (1) 2.

How frequently does the air in your neighborhood smell bad? Frequently N=47 (53%) Occasionally N= 27 (31%) Rarely N= 10 (11%) No answers N=4 (5%) 3. Have you noticed that the smell is worse on the weekdays or weekends? Both N=33 (38%) Not sure N=30 (34%) Weekdays N=15 (17%) Weekends N=7 (8%) No Answer N= 3 (3%) 4. What times of the day do you notice the smell? Check all that apply. Evening N=51 (58%) Morning N=50 (57%) Afternoon N=40 (45%) Middle of the night N=27 (31%) 5. What do you think impacts air quality in your neighborhood? Check all that apply. Oil refineries N=78 (89%) Industrial sources/manufacturing facilities N=58 (66%) Waste incineration plant N=26 (30%) Traffic from trucks and cars N=25 (28%) Water treatment plant N=17 (19%) Not sure N=7 (8%) Landfills N=6 (7%) Other N= 5 (7%) Dumpster (1) People smoking outside (2) soil and water (1) dam (1)

COMMENTS ON AIR QUALITY SMELL-RELATED

I can’t sleep when it smells bad. There are different kinds of smells. I worry about it blowing up (Holly Refinery –lives across the street) Because of the air pollution, it costs me more money to buy inhalers and I can’t hardly function when I go outside Smells like gas. It smells and it is annoying Smells worse when there is wind or heavy air In the summer, it smells bad most of the time The more heat the worse the smell Smells worse when the wind is strong The air quality is worse in the winter on the south side of the refinery when the north winds blow City should try to enact stricter air pollution standards especially in this area Smells like sewer I thought it was just our neighborhood that smells bad Smells like a fart People get used to the smell so they don’t notice it Sometimes I want to get in my car and just drive away because it smells so bad Especially at night It’s the plant over there (Covanta) it burn your nose. I smell it when I ride my bike past it. It’s like bleach. Especially at night. Smell makes me sick to my stomach You can tell the difference between the air on the north and west sides and the air on the south side (smell) I have gotten used to the smell

ENVIRONMENTAL HEALTH-RELATED

I have COPD Have to take inhaler with me all the time Rubs eyes all the time I avoid going outside especially when it’s cold I am worried about my pregnant sister I lived here 50 year. I have COPD and my son who grew up here has asthma Believes bad air is why she feels tired My newborn was born with a disability When I lived on the south side, I didn’t have trouble breathing. Now I do My family gets sick when they go outside My sister has asthma Give my daughter a headache I have been dealing with depression since I moved here Offer health insurance for those who are affected by air pollution There is lots of cancer in this neighborhood (just south of the Holly East refinery), including my husband, mom and neighbors I am worried about the children’s health The air quality is worse in the winter on the south side of the refinery when the north winds blow I am more worried about the water and soil (south of Holly) The kids were playing in the water after the flood (in May) The water tastes bad My sister has asthma. One time my parents told me not to play outside (2016)—12 year old boy I am more worried about the water and soil The apartments need air filters (2)

HUD CHOICE NEIGHBORHOOD- RELATED

The reason that the HUD project does not include Western Pines is because they don’t want to dig up the dirt here because it is contaminated from the refinery It’s good that people are being moved out of here because the air is so bad and I feel sorry for the people who are moving in It doesn’t make sense to build brand new housing here. I don’t consider it live-able here. I don’t know why they are doing it. Everyone who has to leave the apartment should be able to return once the HUD project is complete

HOUSING-RELATED (SOUTH OF REFINERY)

Holly wants to buy my home but they are trying to low ball me Holly used to clean our cars once a month 10-15 years ago House gets dirty more often and I have to wash it more Trailer park owner refuses to sell land to Holly

Response:

The Environmental Protection Agency (EPA) is required by the federal Clean Air Act to set National Ambient Air Quality Standards (NAAQS) for six common air pollutants (known as criteria pollutants). The NAAQS are "ceilings" for concentrations of criteria pollutants in the ambient air. The NAAQS are established using scientific assessments to set ambient standards at levels below those at which adverse health effects have been found or might be expected to occur in sensitive groups. The Air Quality Division operates an ambient air quality monitoring network in order to measure the concentration of pollutants in the ambient air in comparison with the NAAQS, and has established several air monitoring sites in the vicinity of the refinery. These sites are shown in the table below.

AQS Site	Site	Location	Street Address	Latitude	Longitude
400370144	144	Mannford	Mannford Water plant	36.105481	-96.361196
401430174	174	Glenpool	502 E. 144th Pl, Glenpool	35.953708	-96.004975
401430175	175	Tulsa	1710 Charles Page Blvd, Tulsa	36.149877	-96.011664
401430178	178	Lynn Lane	18925 E. 21st St, Tulsa	36.133802	-95.764537
401430179	179	Tulsa Riverside	124 N. Riverside Dr. West	36.154830	-96.015844
401130226	226	Skiatook	1521 S. Lombard, Tulsa	36.355860	-96.012430
401430235	235	Tulsa	2443 S. Jackson Ave, Tulsa	36.126945	-95.998941
401431127	1127	Tulsa (NCore)	3520 1/2 N. Peoria, Tulsa	36.204902	-95.976537

EPA has also established the National Emission Standards for Hazardous Air Pollutants (NESHAP) for control of emissions of hazardous air pollutants (HAP), which include cancer-causing substances such as benzene. The refinery and several adjacent industries (including Covanta) are subject to these standards. Facilities which are subject to NESHAPs are required to implement Maximum Achievable Control Technology (MACT) to control emissions of HAPs, and must monitor the effectiveness of those controls through recordkeeping, monitoring, and reporting requirements. As part of these standards, refineries, including Holly, are required to conduct routine monitoring of concentrations of benzene at the facility fence-line. Recently submitted data was reviewed which indicated compliance with the benzene standard.

In addition to NESHAPs, EPA has established New Source Performance Standards (NSPS), which are a set of technology-based standards for industrial source categories. Certain NSPS apply to petroleum refineries, as well as other sources of emissions adjacent to the refinery.

Similar to the NEHSAPs, NSPS require limits or control technology and impose recordkeeping, reporting, and monitoring requirements.

EPA has developed air dispersion modeling computer programs which predict concentrations of air pollutants downwind of sources. Added impacts from a source and nearby significant sources are determined based on discharge parameters (height, velocity, temperature, location, etc.). In order to conduct an ambient impacts analysis, the impacts of a modification to the facility are added to the measured ambient concentrations of air pollutants and compared to limits of the NAAQS. This comparison is to ensure that the modification will not contribute to an exceedance of the NAAQS. The ambient impacts analysis for this facility is described in Section VII of the "Evaluation of Permit Application No. 2017-1908-C (M-2)(PSD)." No exceedances of NAAQS were determined from the air dispersion modeling and ambient impacts analysis conducted for this facility.

To the extent the commenter discusses various odor, property, and water concerns, those issues are outside the scope of jurisdiction of the Air Quality Division.

This facility is not located within 50 miles of the border with a contiguous state.

Information on all permit actions is available for review by the public in the Air Quality section of the DEQ Web page: www.deq.ok.gov/.

Fee Paid

Part 70 source construction permit application fee of $5,000.

XIII. SUMMARY

The facility has demonstrated the ability to comply with the requirements of the several air pollution control rules and regulations. Ambient air quality standards are not threatened at this site. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

HollyFrontier Tulsa Refining LLC **Permit Number 2017-1908-C (M-2)(PSD)**
Tulsa Refinery East

The permittee is authorized to construct in conformity with the specifications submitted to the Air Quality Division (AQD) on May 2, 2014, with supplemental information received July 27, 2017, September 6, 2018, and July 30, 2019. The Evaluation Memorandum dated February 7, 2020, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. Commencing construction or continuing operations under this permit constitutes acceptance of, and consent to, the conditions contained herein.

SPECIFIC CONDITION 1

The permittee shall be authorized to operate the affected facilities noted in this permit continuously (24 hours per day, every day of the year) subject to the following conditions. Records necessary to show compliance with each of the requirements below must be maintained.
[OAC 252:100-8-6(a)(1)]

a. Combined emissions from Tank 475 and 474 in EUG 20 are limited to 19.578 tons per year (TPY) of volatile organic compounds (VOC). [98-021-TV]

b. Alkylate production is limited to 6,500 BPD based on a 12-month rolling average.

c. The following tank has the throughput limits specified below.

Tank No.	EUG	Throughput Limit
476	20	16,261,905 barrels/year

d. The following units have the noted TPY emission limits. Compliance with all but SO_2 limits are met by throughput limits. See Specific Condition 2, EUG 10 (c) for a description of SO_2 compliance.

EUG	Source	PM_{10}	NO_X	SO_2	VOC	CO
10	SRU #1			34.9		99
10	SRU#2	0.39	10.6	24.6	0.29	24.31

SPECIFIC CONDITION 2

Standards for affected Emission Unit Groups (EUG). [OAC 252:100-8-6(a)]

<u>EUG 3 MACT CC Group 2 Storage Vessels - Fixed Roof (FR)</u>

These storage vessels are regulated under 40 CFR Part 63 Subpart CC (MACT CC) Group 2 Storage Vessels and are limited to the existing equipment as it is.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
112	6195	2012	30'	110’	50,000
118	6201	1907	30'	96'	37,500
119	6202	1907	30'	96'	37,500
126	6263	1907	30'	96'	37,500

a. Fixed roof tanks in EUG 3 are subject to only the recordkeeping requirements of MACT Subpart CC for Group 2 storage vessels, as follow. [40 CFR § 63.654(i)(1)(iv)]

1. Readily accessible records showing the dimensions of each vessel and an analysis of the capacity of each vessel shall be maintained for the life of the vessel. [40 CFR § 63.123(a)]
2. Data, assumptions, and procedures used in determining Group 2 status for these tanks shall be documented. [40 CFR § 63.646(b)(1)]

b. The tanks in EUG 3 are subject to 40 CFR Part 60, Subpart UU (Asphalt Processing and Asphalt Roofing Manufacture) and shall comply with all applicable standards: [40 CFR 60 §§ 470 – 474]

1. § 60.470: Applicability and designation of affected facilities
2. § 60.471: Definitions
3. § 60.472: Standards for particulate matter
4. § 60.473: Monitoring of operations
5. § 60.474: Test methods and procedures

<u>EUG 4 MACT CC Wastewater Tanks</u>

These storage vessels are regulated under 40 CFR Part 63 Subpart CC (MACT CC) as wastewater management units and are limited to the existing equipment as it is. Due to the overlap provisions of MACT CC, the requirements of 40 CFR Part 61 Subpart FF (BWON), and 40 CFR Part 60 Subpart QQQ (NSPS QQQ), these vessels are required to comply with 40 CFR Part 61 Subpart FF to meet the applicable standards under MACT CC, BWON, and NSPS QQQ.

Tank No.	**Point ID**	**Year Built**	**Height**	**Diameter**	**Nominal Capacity**
13	6243	1976	40'	116'	75,250
400	17035	1922	30'	24'	2,400
401	17036	1920	20'	25'	1,700

a. The permittee shall comply with the applicable sections of MACT CC, Wastewater Provisions of § 63.647 for the affected storage tanks. [40 CFR §§ 63.640-654]

1. The permittee shall comply with the requirements of § 61.340 through § 61.355 of 40 CFR Part 61 Subpart FF. To accomplish this, the storage tanks will: [40 CFR § 63.647(a)]

    A. Comply with the Alternative Standards for Storage Tanks of 40 CFR § 61.351 and 40 CFR Part 60 Subpart Kb;
    B. Meet the requirements of 40 CFR § 61.343 for Tanks; or
    C. Be counted as uncontrolled and included in the 6 BQ calculation under §61.355(k).

b. Recordkeeping is required per 40 CFR § 61.356. [40 CFR § 63.654(a)]
c. Reporting is required per 40 CFR § 61.357. [40 CFR § 63.654(a)]

EUG 6 Continuous Catalytic Reforming Unit (CCR)

The CCR is regulated by 40 CFR Part 63, Subpart UUU and is limited to an inorganic HAP concentration of 10 ppmvd corrected to 3% oxygen at the regenerator stack. [40 CFR Part 63, Subpart UUU]

a. The CCR is subject to NESHAP, Subpart UUU and shall comply with all applicable requirements including but not limited to:

1. § 63.1560 What is the purpose of this subpart?
2. § 63.1561 Am I subject to this subpart?
3. § 63.1562 What parts of my plant are covered by this subpart?
4. § 63.1563 When do I have to comply with this subpart?
5. § 63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?
6. § 63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?
7. § 63.1569 What are my requirements for HAP emissions from bypass lines?
8. § 63.1570 What are my general requirements for complying with this subpart?
9. § 63.1572 What are my monitoring installation, operation, and maintenance requirements?
10. § 63.1574 What notifications must I submit and when?
11. § 63.1577 What parts of the General Provisions apply to me?
12. Recordkeeping § 63.1576 What records must I keep, in what form, and for how long?

13. Reporting § 63.1575 What reports must I submit and when?

b. Performance testing as required by NESHAP Subpart UUU shall be repeated within 180 days of completion of modifications on the CCR. [OAC 252:100-43]

EUG 8 Fired Boilers

The boilers are subject to NSPS Subpart J, effective June 30, 2008. These sources are also subject to work practice standards under 40 CFR Part 63 Subpart DDDDD (MACT DDDDD) as initially published on December 23, 2012. Each boiler is fitted with SCR for control of NO_X and compliance is monitored by CEMS.

ID	Point ID	Manufacturer	Model/Burner type	Construction Date
1	6150	Babcock & Wilcox	FH 26	1950
2	6150	Babcock & Wilcox	FH 26	1950
3	6151	Babcock & Wilcox	FH 26	1950
4	6151	Babcock & Wilcox	FH 26	1955

a. Nitrogen oxides emissions shall not exceed 0.20 lbs/MMBTU (3-hr average) or 0.03 lb/MMBTU (annual average). Compliance with this standard shall be demonstrated by use of a continuous emissions monitoring system (CEMS) and the reporting/notification requirements of 40 CFR § 60.7. The CEMS shall meet the requirements of 40 CFR § 60.13 except that the RATAs shall be required every three years. [OAC 252:100-43]

b. All fuel-burning or refuse-burning equipment shall be operated to minimize emissions of VOC. Among other things, such operation shall assure based on manufacturer's data and good engineering practice, that the equipment is not overloaded; that it is properly cleaned, operated, and maintained; and that temperature and available air are sufficient to provide essentially complete combustion. [OAC 252:100-37-36]

c. All boilers are subject to 40 CFR 60 Subpart J, and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J]

1. § 60.104 Standards for sulfur dioxide – (a)(1)
2. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
3. § 60.106 Test methods and procedures – (e)

[40 CFR 60, Subpart J; OAC 252:100-43]

d. Fuel oil shall not be burned except during periods of gas curtailment, operator training, or test runs. [40 CFR § 63.7575]

e. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-31-25]

f. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

[OAC 252:100-19-4]

g. All fuel-burning or refuse-burning equipment shall be operated to minimize emissions of VOC. Among other things, such operation shall assure, based on manufacturer's data and good engineering practice, that the equipment is not overloaded; that it is properly cleaned, operated, and maintained; and that temperature and available air are sufficient to provide essentially complete combustion. [OAC 252:100-37-36]

EUG 9 Fuel-Burning Equipment

Certain heaters have heat input limits, as identified in Specific Condition 1. According to the June 30, 2008 CD, these fuel gas combustion devices (FGDs) are affected facilities under NSPS Subpart J. These sources are also subject to work practice standards under 40 CFR Part 63 Subpart DDDDD (MACT DDDDD).

Source	Point ID	MMBTUH (HHV)	Heater Date
Vacuum	6155	100[2]	1949
FCCU Air Heater (B-1) [1]	6159	38.4 [2]	1949
Unifiner ChargeH-1	6167	42 [2]	1955

(1) vents to FCCU regenerator stack.
(2) estimated capacities per previous owner (Sinclair); June 1998 DEQ facility inspection; not permit limits.

a. All heaters are affected facilities under NSPS J. Provisions include, but are not limited to the following. [40 CFR Part 60, Subpart J; OAC 252:100-43]

1. § 60.104 Standards for sulfur dioxide
2. § 60.105 Monitoring of operations
3. § 60.106 Test methods and procedures

b. All fuel-burning equipment shall be operated and maintained to minimize emissions of VOC. Such conditions mean adherence to manufacturer's recommendations or to good operating and maintenance practices, and that temperature and sufficient air to provide essentially complete combustion are supplied. [OAC 252:100-37-36]

c. Recordkeeping is required as follows:
   1. NSPS J records as required under 40 CFR Part 60 Subpart A. [40 CFR § 60.7]
   2. H_2S CEM to show compliance with SO_2 emission limits. [OAC 252:100-43]
   3. NO_X performance tests for specified heaters. [OAC 252:100-43]

d. Reporting is required for NSPS Subpart J heaters on a semi-annual basis, including the information required in NSPS Subpart A. [40 CFR §§ 60.107 and 60.7]

e. The sulfur content of gas fuel combusted in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

f. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. [OAC 252:100-19-4]

<u>EUG 10 Sulfur Recovery Units</u>

SRU #1 was constructed in 1972 and SRU #2 became operational in June 2006. Each unit has a tail gas treating unit (TGTU) to scrub its exhaust. The TGTU #1 incinerator is rated at 5.6 MMBTUH and the TGTU #2 incinerator is rated at 12.1 MMBTUH.

a. SRU #1 and SRU #2 are subject to NSPS J and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60 Subpart J]

   1. § 60.104 Standards for sulfur dioxide – (a)(2)(i);
   2. § 60.105 Monitoring of operations – (a)(5)(i & ii) & (e)(4)(i);
   3. § 60.106 Test methods and procedures – (a) & (f)(1 & 3).

b. SRU #1 and SRU #2 are subject to NESHAP, Subpart UUU and shall comply with all applicable provisions by the dates specified in § 63.1563(b) including, but not limited to: [40 CFR Part 63 Subpart UUU]

   1. § 63.1568 What are my requirements for HAP emissions from sulfur recovery units? – (a)(1), (b)(1, 3, 4, 5, 6, & 7), & (c)(1 & 2);
   2. § 63.1569 What are my requirements for HAP emissions from bypass lines? – (a)(1 & 3), (b)(1-4), & (c)(1 & 2);
   3. § 63.1570 What are my general requirements for complying with this subpart? – (a) & (c-g);
   4. § 63.1571 How and when do I conduct a performance test or other initial compliance demonstration? – (a) & (b)(1-5);
   5. § 63.1572 What are my monitoring installation, operation, and maintenance requirements? – (a)(1-4) & (d)(1-2);
   6. § 63.1574 What notifications must I submit and when? – (a)(2) & (f)(1, 2(i), 2(ii), 2(viii), 2(ix), & 2(x));
   7. § 63.1575 What reports must I submit and when? – (a-h);

8. § 63.1576 What records must I keep, in what form, and for how long? – (a), (b)(1, 3, 4, 5), & (d-i);
9. § 63.1577 What parts of the General Provisions apply to me?

c. Sulfur pit emissions shall be vented so that they are eliminated, controlled, or included and monitored as part of the emissions subject to Subpart J limits, except during maintenance, start-up, shutdown, upset or malfunction.

d. SRU/TGTU #1 does not have continuous flow monitoring, but it does have CEMS for monitoring concentrations of SO_2 and O_2. Maximum exhaust flow rates established by the most recent performance testing shall be combined with SO_2 CEMS readings to establish hourly and annual SO_2 emissions. Such testing, shall be performed within 60 days after any construction project that increases throughput to the SRU, but at intervals no greater than 12 months. [OAC 252:100-43]

e. Recordkeeping is required as follows.

1. Per NSPS Subparts A and J, including, but not limited to, CEMS information and periods of excess emissions and monitor unavailable time. [40 CFR §§ 60.107 and 60.7]
2. Per MACT Subparts A and UUU, including, but not limited to, CEMS information, periods of excess emissions, SSM records, performance and RATA tests, and Operations, Maintenance, and Monitoring (OMM) records.
[40 CFR §§ 63.1576, 63.6, 63.8 and 63.10]

f. Reports are required as follow.

1. Per NSPS Subparts A and J, including, but not limited to, semi-annual compliance reports and CEMS excess emission report. [40 CFR §§ 60.107 and 60.7]
2. Per MACT Subparts A and UUU, including, but not limited to, semi-annual compliance reports, SSM reports, and CEMS excess emission reports.
[40 CFR §§ 63.1575, 63.6, 63.8, and 63.10]
3. The Projected Actual Emissions of SO_2 were 14.0 TPY for SRU #1 and 9.84 TPY for SRU #2. Any annual emission rate exceeding these levels shall be reported on semi-annual compliance reports, SSM reports, and CEMS excess emission reports until 5 (five) years following the issuance date of this permit. [OAC 252:100-8-36.2(c)]

g. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.
[OAC 252:100-19-4]

EUG 11 FCCU

Emissions Limits:

Pollutant	Emission Limit	Averaging Period	First Compliance Date
SO_2	25 ppmdv @ 0% O_2	365 days rolling	December 31, 2010
	50 ppmdv @ 0% O_2	7 days rolling	January 7, 2010
NOx	20 ppmdv @ 0% O_2	365 days rolling	December 31, 2010
	40 ppmdv @ 0% O_2	7 days rolling	January 7, 2010
PM	1 lb PM / 1,000 lbs coke burn-off	3-hours	June 30, 2008
CO	500 ppm@ 0% O_2	1-hour	June 30, 2008

a. The FCCU is subject to 40 CFR Part 63 Subpart UUU (MACT UUU) and shall comply with all applicable requirements including but not limited to: [40 CFR Part 63 Subpart UUU]

1. §63.1560 What is the purpose of this subpart?
2. §63.1561 Am I subject to this subpart?
3. §63.1562 What parts of my plant are covered by this subpart?
4. §63.1563 When do I have to comply with this subpart?
5. §63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?
6. §63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?
7. §63.1570 What are my general requirements for complying with this subpart?
8. §63.1572 What are my monitoring installation, operation, and maintenance requirements?
9. §63.1574 What notifications must I submit and when?
10. §63.1575 What reports must I submit and when?
11. §63.1576 What records must I keep, in what form, and for how long?
12. §63.1577 What parts of the General Provisions apply to me?

b. The FCCU shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR Part 60, Subpart Ja]

1. § 60.102a Emissions limitations;
2. § 60.103a Design, equipment, work practice or operational standards;
3. § 60.104a Performance tests;
4. § 60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU); and
5. § 60.108a Recordkeeping and reporting requirements.

c. The FCCU is an affected facility under NSPS Subpart A (General Requirements) and shall comply with all applicable requirements.

d. A Selective Catalytic Reduction system shall be operated on the discharges from the FCCU to meet the NOx emissions limits above.

e. NOx and SO_2 emissions and O_2 concentrations shall be monitored continuously using continuous emission monitoring systems which are certified using the procedures of 40 CFR Part 60, Appendix B and F. Records of daily, 7-day rolling average, and 365-day rolling averages shall be kept.

f. Recordkeeping
   1. NSPS Subpart Ja, MACT Subparts A and UUU, including, but not limited to, CEMS and COMS information, periods of excess emissions, SSM records, performance and RATA tests, and OMM records.

[40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart UUU]

g. Reporting per NSPS Subpart Ja, MACT Subparts A and UUU, including, but not limited to, semi-annual compliance reports, SSM reports, and CEMS excess emission reports.

[40 CFR Part 60 Subpart Ja and 40 CFR Part 63 Subpart UUU]

h. Emissions during periods of start-up, shutdown, or malfunction of the FCCU or FCCU emissions control system will not be used in determining compliance with the 7-day average limits for NOx or CO.

i. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C. [OAC 252:100-19-4]

<u>EUG 12 Flares</u>

Sources in other EUGs under various regulations utilize the flares as air pollution control devices. Monitoring, recordkeeping, and reporting requirements related to flare pilot monitoring are found in each affected EUG, and not included here.

Flare	Make/Model	Height (ft)	Date
#1	Zink/STF-SA-18	230	1949
#2	Zink/STF-SA-36-C	250	1972

a. The flares are regulated under 40 CFR Part 60 Subpart A and 40 CFR Part 63 Subpart A. Requirements include, but are not limited to:

   1. General control device requirements [40 CFR § 60.18]
   2. Control device requirements [40 CFR § 63.11]

b. The flares shall be monitored continuously for the presence of a pilot flame.

[40 CFR § 60.18(f)]

c. The flares are subject to New Source Performance Standards (NSPS), Subpart Ja, and shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to:

[40 CFR Part 60, Subpart Ja]

1. § 60.102a Emissions limitations;
2. § 60.103a Design, equipment, work practice or operational standards;
3. § 60.104a Performance tests;
4. § 60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares; and
5. § 60.108a Recordkeeping and reporting requirements.

d. EPA has recognized that periodic maintenance may be required for properly designed and operated flare gas recovery system. The permittee shall take all reasonable measures to minimize emissions while such periodic maintenance is being performed. The Flare Gas Recovery system may be bypassed in the event of an emergency or in order to ensure safe operation of the refinery process. Nothing precludes the permittee from temporarily bypassing a flare gas recovery system under such circumstances. Otherwise, a flare gas recovery system shall be maintained to control continuous or routing combustion.

e. The permittee shall comply with the requirements for flare control devices in 40 CFR Part 63, Subpart CC, including but not limited to presence of a pilot flame, visible emissions, flare tip velocity, heating value of gases combusted, and volumetric flow monitoring.

[40 CFR § 63.670]

<u>EUG 13 MACT EEEE Tanks</u>

This EUG contains vessels subject to 40 CFR Part 63 Subpart EEEE. Because these perchloroethylene tanks are smaller than 5,000 gallons, Subsection 63.2343(a) indicates that these emission sources do not require control.

Tank No.	Location	Year Built	Height	Diameter	Nominal Capacity
10F-163	CCR	2007	4'	8'	18 bbl
4V-31	Unifiner	2002	13.5'	4.5'	30 bbl

<u>EUG 15 High Vapor Pressure Loading Operations</u>

There are several loading racks that handle VOC materials.

Rack	Point ID	Material	Capacity	Date
Butane truck	6171	Butane loading and unloading	4 trucks	1923
Propylene	13404	Propylene loading	2 trucks	Trucks/1997

a. All loading and vapor lines shall be equipped with fittings that make vapor-tight connections and which must be closed when disconnected or which close automatically when disconnected.

[OAC 252:100-37-16]

b. A means shall be provided to prevent VOC drainage from the loading device when it is removed from the transport vessel, or to accomplish complete drainage before removal.
[OAC 252:100-39-41(c)]

c. Each delivery vessel shall meet one of the following requirements. [OAC 252:100-39-41(d)]

i. The delivery vessel must be designated and operated to be vapor tight except when sampling, gauging, or inspecting.
ii. The delivery vessel must be equipped and operated to deliver the VOC vapors to a vapor recovery/disposal system.
iii. No owner or operator shall allow a delivery vessel to be filled at a facility unable to receive displaced VOC vapors nor service vessels unable to deliver displaced vapors except for vessels and facilities exempted in 252:100-39-41(b) and 252:100-39-41(c).
iv. Testing of the tank trucks for compliance with the vapor tightness requirements must be consistent with 252:100-39-41(e)(4)(B)(ii), or an equivalent method as determined by the Division Director.

d. Stationary loading facilities shall be checked annually in accordance with EPA Test Method 21 or an alternative work practice for monitoring equipment for leaks consistent with 40 CFR Section 60.18(g) through 60.18(i). Leaks greater than 5,000 ppmv measured by EPA Test Method 21 or leaks detected by an alternative work practice for monitoring equipment leaks, 184 shall be repaired within 15 days. Facilities shall retain inspection and repair records for at least two years. [OAC 252:100-39-41(e)]

EUG 16 Fugitive Emissions

Equipment leaks from the existing refinery, including but not limited to the process units, storage tanks, and the terminal are included in this Group. There are no emission limits applied to this EUG under Title V but it is limited to the existing equipment as it is. Because all equipment leaks are subject to the LDAR requirements of OAC 252:100-39-15 and some are also subject to LDAR requirements of NSPS Subparts GGG or GGGa, or to the LDAR requirements of MACT CC, the permittee will comply by meeting the following conditions. Under the requirements of the consent decree, all existing units accept NSPS Subpart GGG applicability. Units constructed for the Heavy Crude Processing Expansion project under Permit No. 2007-005-TV (M-1) and the Distillate Hydrotreater Unit, Continuous Catalytic Reformer Unit, Naphtha Splitter, and Flare Gas Recovery Unit are subject to NSPS Subpart GGGa. (The Sodium Hydrosulfide (NaSH) Unit will process inorganic materials, therefore, is not subject to NSPS Subpart GGGa.)
[40 CFR § 60.590, 40 CFR § 60.590a, and OAC 252:100-39-15]

a. All affected equipment, in HAP service (contacting > 5% by weight HAP), shall comply with NESHAP, 40 CFR 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component. [40 CFR Part 63, Subpart CC]

1. § 63.642 General Standards – (c), (d)(1), (e), & (f);
2. § 63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
3. § 63.654 Reporting and Recordkeeping Requirements – (d), & (f-h).

b. Equipment constructed or modified after January 4, 1983, and on or before November 7, 2006, determined not to be in HAP service (contacting < 5% by weight HAP) and which is in VOC service (contacting > 10% by weight VOC) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG. [40 CFR Part 60, Subpart GGG]

   1. § 60.592 Standards (a-e).
   2. § 60.593 Exceptions (a-e).
   3. These conditions reference the standards are described in § 60.592 by reference to NSPS Subpart VV §§60.482-1 through 60.482-10. Test methods and procedures, record-keeping, and reporting are described in §§60.485, 486, and 487, respectively.

c. Equipment constructed or modified after November 7, 2006, determined not to be in HAP service (contacting < 5% by weight HAP) and which is in VOC service (contacting > 10% by weight VOC) shall comply with the requirements of NSPS 40 CFR 60, Subpart GGGa. [40 CFR Part 60, Subpart GGGa]

   1. § 60.592a Standards (a-e).
   2. § 60.593a Exceptions (a-e).
   3. These conditions reference the standards are described in § 60.592a by reference to NSPS Subpart VVa §§60.482-1a through 60.482-10a. Test methods and procedures, record-keeping, and reporting are described in §§60.485a, 486a, and 487a, respectively.

d. Certain equipment is regulated as described in OAC 252:100-39-15.

e. Permittee shall maintain records identifying which components are regulated under each of the requirements listed in a, b, and c preceeding.

f. Recordkeeping provisions for these regulations are very extensive and are not summarized here. Records for components covered by the above requirements are found in the applicable rule. [40 CFR §63.654, 40 CFR §60.486, and OAC 252:100-39-15]

g. Reporting provisions for these regulations are very extensive and are not summarized here. A single report may be submitted to comply with all of the reporting requirements above, so long as all reporting requirements for each regulation are included. [40 CFR § 63.654, 40 CFR § 60.487, and OAC 252:100-39-15]

<u>EUG 17 Wastewater System</u>

The wastewater system consists of several different sewer systems and the wastewater treatment plant, as described in Part N of Section II (Facility Description) above. The facility is subject to 40 CFR Part 61 Subpart FF (BWON) and 40 CFR Part 63 Subpart CC (MACT CC), while areas of the refinery are subject to 40 CFR Part 60 Subpart QQQ (NSPS QQQ). Due to the overlap regulations under MACT CC (40 CFR § 63.640(o)), all Group 1 wastewater streams also regulated under NSPS QQQ must meet only MACT CC standards, while all Group 1 wastewater streams also regulated under BWON must meet only BWON standards. A June 11, 2007, EPA Applicability Determination (AD) issued to BP Products North America and signed by George Czerniak, states that a Group 2 wastewater stream may be treated under BWON exclusively if the facility declares it to be Group 1 and satisfies the requirements of Subpart FF for the stream. Given this AD, the entire SCAN Unit, entire NHDS Unit, and new construction at the DHTU and CCR are subject to BWON. Aggregated emission points are identified as Point ID 13409.

a. The Refinery is subject to NESHAP, 40 CFR Part 61, Subpart FF and shall comply with all applicable requirements. [40 CFR Part 61, NESHAP, Subpart FF]

1. § 61.342 Standards: General.
2. § 61.343 Standards: Tanks.
3. § 61.344 Standards: Surface Impoundments.
4. § 61.345 Standards: Containers.
5. § 61.346 Standards: Individual drain systems.
6. § 61.347 Standards: Oil-water separators.
7. § 61.348 Standards: Treatment processes.
8. § 61.349 Standards: Closed-vent systems and control devices.
9. § 61.350 Standards: Delay of repair.
10. § 61.351 Alternative standards for tanks.
11. § 61.352 Alternative standards for oilwater separators.
12. § 61.353 Alternative means of emission limitation.
13. § 61.354 Monitoring of operations.
14. § 61.355 Test methods, procedures, and compliance provisions.
15. § 61.356 Recordkeeping requirements.
16. § 61.357 Reporting requirements.

b. These records will be maintained in accordance with the recordkeeping requirements under 40 CFR § 61.356.

c. These reports will be maintained in accordance with the reporting requirements under 40 CFR § 61.357.

EUG 18 Hydrocarbon Recovery System

The Hydrocarbon Recovery Tanks, all of which were constructed between 2007 and 2009, are subject to MACT GGGGG. They share a common Point ID of 14487. This EUG has no emission limitation.

Tank No.	Height (feet)	Diameter (feet)	Nominal Capacity
B1	6	3.8	12 bbl
B2	6	3.8	12 bbl
B4	6	3.8	12 bbl
B5	N/A	N/A	55 gallons
B7	6	3.8	12 bbl
B8	6	3.8	12 bbl
B9	6	3.8	12 bbl
B10	6	3.8	12 bbl

Tank No.	Height (feet)	Diameter (feet)	Nominal Capacity
B11	6	3.8	12 bbl
B12	6	3.8	12 bbl

a. Site remediation activities at the refinery are subject to 40 CFR Part 63 Subpart GGGGG and the refinery shall comply with any applicable requirements including but not limited to:
[40 CFR Part 63 Subpart GGGGG]

1. § 63.7880 - 7883 What This Subpart Covers
2. § 63.7884 - 7888 General Standards
3. § 63.7890 - 7893 Process Vents
4. § 63.7895 - 7898 Tanks
5. § 63.7900 - 7903 Containers
6. § 63.7920 - 7922 Equipment Leaks
7. § 63.7935 - 7938 General Compliance Requirements
8. § 63.7950 - 7953 Notifications, Reports, and Recordkeeping
9. § 63.7955 - 7957 Other Requirements and Information
10. The permittee shall comply with the provisions of 40 CFR Part 63 Subpart A as specified in Appendix to Subpart GGGGG, Table 3.

EUG 19 Cooling Towers

Number	Point ID	Purpose	Date
3	25053	Cooling water for the FCCU	1949
3a	25054	Cooling water for SCANfiner	2003
4 and 5	25055	Cooling water for the CDU	1949
7	25056	Cooling water for the ALKY, POLY & ISOM	2007*
8	25057	Cooling water for the OIF	1972
7a	25056a	Cooling water for the ALKY, POLY & ISOM	2012

* Replaced tower built in 1949.

a. These cooling towers shall comply with 40 CFR § 63.654 and 40 CFR § 63.655 upon the effective compliance date.

EUG 20 NSPS Kb Tanks (EFR) - MACT CC Group 1 Wastewater

These storage vessels are regulated under 40 CFR Part 60, Subpart Kb and are limited to the existing equipment as it is. Due to the overlap provisions of MACT CC, the vessels are required to comply only with Kb, except as noted in 40 CFR § 63.640(n)(8).

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
476	36590	2005	45'	55’	15,000
478	N/A	2014	59	102’	100,000
477	N/A	2006	40’	30’	5,000
474	15940	1997	48'	106'	73,000
475	15941	1997	48'	106'	73,000

a. The EFR tanks in EUG 20 are subject to NSPS Subpart Kb and shall comply with all applicable requirements. The “overlap” provisions of MACT CC [§ 63.640(n)(1)] state that these storage vessels are required only to comply with the provisions of Kb, with the modifications noted in § 63.640(n)(8).

1. Mechanical design and operating specifications. [40 CFR § 60.112b(a)(2)]
2. Compliance testing and procedures. [40 CFR § 60.113b(b)]
3. Monitoring provisions [40 CFR §60.116b]

b. Tanks in this EUG may be used in MACT CC Group 1 wastewater service as they comply with the Alternative Standards for Storage Tanks of 40 CFR § 61.351 and 40 CFR Part 60 Subpart Kb.

c. The sliding cover shall be in place over the slotted-guidepole opening through the floating roof at all times except when the sliding cover must be removed for access. Visually inspect the deck fitting for the slotted guidepole at least once every 10 years and each time the vessel is emptied and degassed. If the slotted guidepole deck fitting or control device(s) have defects, or if a gap or more than 0.32 centimeters (1/8 inch) exists between any gasket required for control of the slotted guidepole deck fitting and any surface that it is intended to seal, such items shall be repaired before filling or refilling the storage vessel with regulated material. Tanks out of hydrocarbon service, for any reason, do not have to have any controls in place during the time they are out of service.
[EPA’s Storage Tank Emission Reduction Partnership Agreement]

d. Recordkeeping requirements include:

1. Inspection results, dimensions and capacity of the storage vessels, VOL stored, period of storage, and maximum TVP. [40 CFR § 60.115b and 116b]

e. Reporting requirements include semi-annual reporting of deviations during inspections, notifications, and initial certifications. [40 CFR §§ 60.115b and 63.640(n)(8)(v)]

EUG 21 Pressurized Spheres

There are no emission limits applied to this EUG under Title V but it is limited to the existing equipment as it is. Because there are no measurable emissions from any of these tanks, they are all classified as Insignificant.

Tank No.	Point ID	Year Built	Diameter (feet)	Nominal Capacity (bbls)
207	6281	1948	48	9,250
208	6282	1924	48	9,250
218	6284	1986	55	13,750
219	6285	1986	55	13,750
220	6286	1953	51	10,800
221	6287	1953	51	10,800

a. Each vessel shall be a pressure vessel capable of maintaining working pressures that prevent the loss of VOC vapor or gas to the atmosphere. [OAC 252:100-39-41(a)]

EUG 22 Pressurized Bullet Tanks

Because there are no measurable emissions from these tanks, they are all classified as Insignificant.

Tank No.	Point ID	Year Built	Length (feet)	Diameter (feet)	Nominal Capacity (bbls)
58	6288	1960	66	12	1,300
59	6289	1960	66	12	1,300
60	6290	1960	66	12	1,300
64	6291	1967	84	10	1,300
65	6292	1967	84	10	1,300
66	6293	1967	84	10	1,300
70	6294	1979	70	11	1,000
71	6295	1979	70	11	1,000
72	6296	1998	78	10	1,000
73	6297	1998	78	10	1,000

a. Each vessel shall be a pressure vessel capable of maintaining working pressures that prevent the loss of VOC vapor or gas to the atmosphere. [OAC 252:100-39-41(a)]

EUG 23 MACT CC Group 2 Wastewater Tanks

These tanks are affected facilities under MACT CC, but there are no standards or requirements under CC. Therefore, the only requirements are those of NESHAP Subpart FF.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
52	22638	1972	36'	40'	7,500
56	36193	1992	16'	25'	1,400
57	36193	1992	16'	25'	1,400
140	23134	1971	16'	36'	2,900
369	23134	1960	23'	12'	480

EUG 24 Tanks Subject to NESHAP FF

The following tank is subject to the benzene waste organic NESHAP, but is too small to be an affected facility under the Refinery MACT.

Tank No.	Point ID	Year Built	Height	Diameter	Nominal Capacity
67	23134	1992	12'	10'	165

EUG 25 New Fuel-Burning Equipment with Heat Input < 100 MMBTUH (NSPS Subpart J)

This EUG contains new fuel-burning equipment with heat input less than 100 MMBTUH. These sources are subject to regulation under 40 CFR Part 63 Subpart DDDDD (MACT DDDDD).

Source	Point ID	MMBTUH (HHV)	Const. Date	NOx lb/MMBTU (HHV)
Scanfiner Charge (12H-101)	23133	25.2	2004	0.07
NHDS Charge (02H-001)	36580	39	2006	0.05
NHDS Stripper Reboiler (02H-002)	36584	44.2	2006	0.05

a. Compliance with the SO_2 limits is demonstrated by compliance with the H_2S limit imposed on fuel gas combustion devices by NSPS Subpart J and fuel input. Compliance with the fuel input limits will be calculated by using the monthly fuel input to calculate hourly average heat input. [40 CFR Part 60, Subpart J and OAC 252:100-43]

b. Compliance with the NO_X limits is demonstrated by performance testing of the low-NO_X burners. Compliance with these limits is demonstrated by heat input to each unit, using monthly fuel inputs to calculate hourly averages. [OAC 252:100-43]

c. All heaters must comply with 40 CFR Part 60 Subpart J, and shall comply with all applicable provisions including but not limited to: [40 CFR Part 60, Subpart J and OAC 252:100-43]

1. § 60.104 Standards for sulfur dioxide – (a)(1)
2. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
3. § 60.106 Test methods and procedures – (e)

d. Compliance with the H_2S destruction efficiency criterion and H_2S emission limitation of OAC 252:100-31-25 concerning the SCANfiner process unit shall be demonstrated using the SRU CEMS or through engineering calculations and judgment. [OAC 252:100-31]

e. Recordkeeping is required as follows:

1. NSPS J records as required under 40 CFR Part 60 Subpart A. [40 CFR § 60.7]
2. H_2S CEM to show compliance with SO_2 emission limits for specified heaters. [OAC 252:100-43]
3. NOx performance tests for specified heaters. [OAC 252:100-43]
4. Monthly fuel use for each piece of fuel-burning equipment in EUG 25 with a heat input limit shall be maintained, along with a calculation demonstrating that the average hourly firing rate of each item is not greater than the heat rate set forth in SC #1. These records shall be maintained on a 12-month rolling basis. [OAC 252:100-43]

f. Reporting is required for NSPS Subpart J heaters on a semi-annual basis, including the information required in NSPS Subpart A. [40 CFR §§ 60.107 and 60.7]

g. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

h. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

[OAC 252:100-19-4]

i. All fuel-burning equipment shall be operated and maintained to minimize emissions of VOC. Such conditions mean adherence to manufacturer's recommendations or to good operating and maintenance practices, and that temperature and sufficient air to provide essentially complete combustion are supplied. [OAC 252:100-37-36]

EUG 26 New/Modified Fuel-Burning Equipment with Heat Input ≥ 100 MMBTUH

These sources are all regulated under NSPS Subpart Ja and 40 CFR Part 63 Subpart DDDDD (MACT DDDDD).

Source	Point ID	MMBTUH (HHV)	Const. Date	NOx lb/MMBTU (HHV)
CCR #1 Interheater (10H-113)	39225	155	2005	0.05
Naphtha Splitter Reboiler Heater (10H-105)	6162	100	Pending	0.03
FCCU Charge Heater B-2	6158	165	Pending	0.03

a. Compliance with the SO_2 limit is demonstrated by compliance with the H_2S limit imposed on fuel gas combustion devices by NSPS Subpart Ja and fuel input. Compliance with the fuel input limits will be calculated by using the monthly fuel input to calculate hourly average heat input. [40 CFR Part 60, Subpart Ja and OAC 252:100-43]

b. Compliance with the NO_X limit is demonstrated by performance testing of the low-NO_X burners and CEMS as required by NSPS Subpart Ja. Compliance with these limits is demonstrated by heat input to each unit, using monthly fuel inputs to calculate hourly averages. [OAC 252:100-43]

c. All heaters must comply with 40 CFR 60 Subpart Ja, and shall comply with all applicable provisions including but not limited to: [40 CFR 60, Subpart Ja and OAC 252:100-43]

1. §60.100a Applicability, designation of affected facility, and reconstruction.
2. §60.101a Definitions.
3. §60.102a Emissions limitations.
4. §60.103a Design, equipment, work practice or operational standards.
5. §60.104a Performance tests.
6. §60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).
7. §60.106a Monitoring of emissions and operations for sulfur recovery plants.
8. §60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.
9. §60.108a Recordkeeping and reporting requirements.
10. §60.109a Delegation of authority.

d. Recordkeeping is required as follows:

1. NSPS Ja records as required under 40 CFR Part 60 Subpart A. [40 CFR § 60.7]
2. H_2S CEMS to show compliance with SO_2 emission limits for specified heaters. [OAC 252:100-43-4]
3. NO_X performance tests for specified heaters. [OAC 252:100-43-3]

4. Monthly fuel use for each piece of fuel-burning equipment with a heat input limit shall be maintained, along with a calculation demonstrating that the average hourly firing rate of each item is not greater than the heat rate set forth in SC #1. These records shall be maintained on a 12-month rolling basis. [OAC 252:100-43-7]

e. Reporting is required for NSPS Subpart Ja heaters on a semi-annual basis, including the information required in NSPS Subpart A. [40 CFR §§ 60.108a and 60.7]

f. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

g. 10H-105 shall have the following emissions limits:

Unit Capacity	**Pollutant**	**Emission Limits, lb/MMBTU**	**Emission Limits**	
			lb/hr	**TPY**
100 MMBTUH	NO_X	0.03*	3.00	13.1
	CO	0.04*	4.00	17.5
	VOC	--	0.54	2.36
	SO_2	NSPS Subpart Ja	2.64	4.28
	PM_{10} / $PM_{2.5}$	0.0075*	0.75	3.26

*BACT limit; 3-hour average.

h. Heater B-2 shall have the following emissions limits:

Unit Capacity	**Pollutant**	**Emission Limits, lb/MMBTU**	**Emission Limits**	
			lb/hr	**TPY**
165 MMBTUH	NO_X	0.03*	4.95	21.68
	CO	0.04*	6.60	28.91
	VOC	--	0.89	3.90
	SO_2	NSPS Subpart Ja	4.29	7.08
	PM_{10} / $PM_{2.5}$	0.0075*	1.24	5.42

*BACT limit, 3-hour average.

i. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

[OAC 252:100-19-4]

j. All fuel-burning equipment shall be operated and maintained to minimize emissions of VOC. Such conditions mean adherence to manufacturer's recommendations or to good operating and maintenance practices, and that temperature and sufficient air to provide essentially complete combustion are supplied. [OAC 252:100-37-36]

EUG 27 Existing Fuel-Burning Equipment Accepting NO_X Limits

The following table shows available information for certain heaters.

Source	Point ID	MMBTUH (HHV)	Heater Date	NOx lb/MMBTU (HHV)
DHTU Reactor Charge 1H-101	6156	80	1972 **	0.05
CCR Charge Heater 10H-101	6163	120	1972*	0.05
CCR Inter-heater #2-1 10H-102	6163	101	1972	0.15
CCR Interheater #2-2 10H-103	6163	25	1972	0.15
CCR Stabilizer Reboiler 10H-104	6162	85	1972*	0.05

* low-NO_X burners installed in 2005.
**Low-NOx burners installed in 2011.

a. Compliance with the NO_X limits is demonstrated by performance testing of the low-NO_X burners. Compliance with these limits is demonstrated by heat input to each unit, using monthly fuel inputs to calculate hourly averages.

b. CCR Charge Heater 10H-101, CCR Interheater #2-1 10H-102, and CCR Interheater #2-2 10H-103. For performance testing when all three units are operating, a combined limit of 0.13 lb/MMBTU NOx shall apply. Total NOx from the three heaters shall not exceed 136.7 TPY.

c. Monthly fuel use for each piece of fuel-burning equipment with a heat input limit shall be maintained, along with a calculation demonstrating that the average hourly firing rate of each item is not greater than the heat rate set forth above. These records shall be maintained on a 12-month rolling basis. [OAC 252:100-43-7]

d. Per CD 08CV 020-D, these heaters are affected facilities under NSPS Subpart J and shall comply with all applicable requirements, including, but not necessarily limited to the following.

1. §60.104 Standards for sulfur oxides. The CD requires compliance no later than December 31, 2010.
2. §60.105 Monitoring of emissions and operations.
3. §60.106 Test methods and procedures.
4. §60.107 Reporting and recordkeeping requirements.
5. §60.108 Performance test and compliance provisions.

e. The sulfur content of gas fuel in fuel-burning equipment shall not exceed 60 ppm, annual average. The sulfur content shall be monitored using a CEMS which complies with NSPS, Subpart Ja. Records of monitoring results shall be kept. [OAC 252:100-8-6(a)]

f. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

[OAC 252:100-19-4]

g. All fuel-burning equipment shall be operated and maintained to minimize emissions of VOC. Such conditions mean adherence to manufacturer's recommendations or to good operating and maintenance practices, and that temperature and sufficient air to provide essentially complete combustion are supplied. [OAC 252:100-37-36]

<u>EUG-28 LPG Unit Fugitive VOC Leakage</u>

EU	Point	Equipment	Estimated Number of Items	Installed Date
LPG	N/A	Fugitive VOC Leakage Components at LPG Recovery Unit	150 gas/vapor valves	2014 - 2015
			150 light liquid valves	
			5 heavy liquid valves	
			660 flanges	
			8 light liquid pumps	
			2 heavy liquid pumps	
			15 gas relief valves	

a. The above process units are subject to NSPS Subpart GGGa and shall comply with all applicable requirements for leak detection and repair. [40 CFR §60.592(a)]

b. The owner operator shall comply with the requirements of §§ 60.482-1a through § 60.482-11a except as provided in § 60.593a:

1. The operator shall demonstrate compliance with §§ 60.482-1a through 60.482-10a for all affected equipment within 180 days of initial startup which shall be determined by review of records, reports, performance test results, and inspection using methods and procedures specified in § 60.485a unless the equipment is in vacuum service and is identified as required by § 60.486a(e)(5). [§ 60.482-1a(a), (b), & (d)]
2. The owner or operator shall comply with the monitoring, inspection, and repair requirements, for pumps in light liquid service, of §§ 60.482-2a(a), (b), and (c) except as provided in §§ 60.482-2a(d), (e), and (f).
3. Compressors in hydrogen service are exempt from the requirements of § 60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.

[§ 60.593a(b)(1)]

4. The owner or operator shall comply with the operation and monitoring requirements, for pressure relief devices in gas/vapor service, of §§ 60.482-4a(a) and (b) except as provided in § 60.482-4a(c) and (d).
5. The owner or operator shall comply with the applicable standards of § 60.482-5a for sampling connection systems.
6. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall be closed at all other times. [§ 60.482-6a]
7. The owner operator shall comply with the monitoring, inspection, and repair requirements, for valves in gas/vapor service and light liquid service, of §§ 60.482-7a(b) through (e), except as provided in § 60.482-7a(f), (g), and (h), §§ 60.483-1a, 60.483-2a, and 60.482-1a(c). [§ 60.482-7a(a)]
8. The owner operator shall comply with the monitoring and repair requirements, or pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, of §§ 60.482-8a(a) through (d). [§ 60.482-8a]
9. Delay of repair of equipment is allowed if it meets one of the requirements of §§ 60.482-9a(a) through (e).
10. The owner or operator using a closed vent system and control device to comply with these provisions shall comply with the design, operation, monitoring and other requirements of §§ 60.482-10a(b) through (m). [§ 60.482-10a(a)]
11. The owner or operator shall comply with the applicable standards of § 60.482-11a for connectors in gas/vapor service and in light liquid service.
12. An owner or operator may elect to comply with the alternative requirements for valves of §§ 60.483-1a and 60.483-2a. [§ 60.592a(b) & § 60.482-1a(b)]
13. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the test method and procedures of § 60.485a except as provided in §§ 60.593a. [§ 60.592a(d)]
14. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the recordkeeping requirements of § 60.486a and the reporting requirements of § 60.487a. [§ 60.592a(e)]

<u>EUG-29 New Heaters (Subpart Ja)</u>

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
DHTU	50-MMBTUH DHTU Helper Heater	0.38	1.64	1.30	2.15	1.50	6.57	0.25	1.10	2.00	8.76
NHDS	10-MMBTUH NHDS Helper Heater	0.08	0.33	0.26	0.43	0.30	1.31	0.05	0.22	0.40	1.75
CCR	25-MMBTUH CCR Helper Heater	0.19	0.82	0.65	1.07	0.75	3.28	0.12	0.55	1.00	4.38

a. The above new combustion units shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR Part 60, Subpart Ja]

1. §60.100a Applicability, designation of affected facility, and reconstruction.
2. §60.101a Definitions.
3. §60.102a Emissions limitations.
4. §60.103a Design, equipment, work practice or operational standards.
5. §60.104a Performance tests.
6. §60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).
7. §60.106a Monitoring of emissions and operations for sulfur recovery plants.
8. §60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.
9. §60.108a Recordkeeping and reporting requirements.
10. §60.109a Delegation of authority.

b. The above units shall be fueled with refinery fuel gas or pipeline-grade natural gas only.

[OAC 252:100-8-6(a)(1) and OAC 252:100-31]

c. NOx emissions from each above heater shall not exceed 0.03 lb/MMBTU (3-hour average), expressed as NO_2. CO emissions shall not exceed 0.04 lb/MMBTU (3-hour average). CO_2e emissions shall not exceed 146 lb/MMBTU. PM emissions shall not exceed 0.0076 lb/MMBTU. [OAC 252:100-8-34(b)]

d. Performance testing as required by 40 CFR Part 60.8 shall be conducted within 60 days of achieving maximum production rate, not to exceed 180 days from initial start-up.

[40 CFR § 60.8]

e. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

[OAC 252:100-19-4]

f. All fuel-burning equipment shall be operated and maintained to minimize emissions of VOC. Such conditions mean adherence to manufacturer's recommendations or to good operating and maintenance practices, and that temperature and sufficient air to provide essentially complete combustion are supplied. [OAC 252:100-37-36]

<u>EUG-30 ROSE Unit Fugitive Leaks</u>

<table>
<tr><th>EU</th><th>Point</th><th>Equipment</th><th>Estimated Number of Items</th><th>Installed Date</th></tr>
<tr><td rowspan="8">ROSE</td><td rowspan="8">N/A</td><td rowspan="8">Fugitive VOC Leakage Components at ROSE Unit</td><td>200 gas/vapor valves</td><td rowspan="8">2014 - 2015</td></tr>
<tr><td>300 light liquid valves</td></tr>
<tr><td>70 heavy liquid valves</td></tr>
<tr><td>1,204 flanges</td></tr>
<tr><td>10 light liquid pumps</td></tr>
<tr><td>5 heavy liquid pumps</td></tr>
<tr><td>2 compressor seals</td></tr>
<tr><td>15 gas relief valves</td></tr>
</table>

a. The above process units are subject to NSPS Subpart GGGa and shall comply with all applicable requirements for leak detection and repair. [40 CFR § 60.592(a)]

b. The owner operator shall comply with the requirements of §§ 60.482-1a through § 60.482-11a except as provided in § 60.593a:

<u>EUG 32: DHTU, NHDS Unit, Alky Unit, FCCU Regenerator Unit, and Naphtha Fractionation Column Fugitive VOC Leaks</u>

<table>
<tr><th>EU</th><th>Point</th><th>Equipment</th><th>Estimated Number of Items</th><th>Installed Date</th></tr>
<tr><td rowspan="5">DHTU</td><td rowspan="5">N/A</td><td rowspan="5">Fugitive VOC Leakage Components at DHTU Unit</td><td>20 gas/vapor valves</td><td rowspan="5">2014 - 2015</td></tr>
<tr><td>45 light liquid valves</td></tr>
<tr><td>2 light liquid pumps</td></tr>
<tr><td>144 flanges</td></tr>
<tr><td>5 gas relief valves</td></tr>
<tr><td rowspan="5">NHDS</td><td rowspan="5">N/A</td><td rowspan="5">Fugitive VOC Leakage Components at NHDS Unit</td><td>20 gas/vapor valves</td><td rowspan="5">2014 - 2015</td></tr>
<tr><td>45 light liquid valves</td></tr>
<tr><td>2 light liquid pumps</td></tr>
<tr><td>144 flanges</td></tr>
<tr><td>5 gas relief valves</td></tr>
<tr><td rowspan="5">Alky</td><td rowspan="5">N/A</td><td rowspan="5">Fugitive VOC Leakage Components atAlky Unit</td><td>20 gas/vapor valves</td><td rowspan="5">2014 - 2015</td></tr>
<tr><td>45 light liquid valves</td></tr>
<tr><td>2 light liquid pumps</td></tr>
<tr><td>144 flanges</td></tr>
<tr><td>5 gas relief valves</td></tr>
<tr><td rowspan="5">FCCU Regenerator</td><td rowspan="5">N/A</td><td rowspan="5">Fugitive VOC Leakage Components at FCCU Regenerator Unit</td><td>50 gas/vapor valves</td><td rowspan="5">2014 - 2015</td></tr>
<tr><td>75 light liquid valves</td></tr>
<tr><td>3 light liquid pumps</td></tr>
<tr><td>268 flanges</td></tr>
<tr><td>6 gas relief valves</td></tr>
</table>

EU	Point	Equipment	Estimated Number of Items	Installed Date
Naphtha Fraction-ation	N/A	Fugitive VOC Leakage Components at Naphtha Fractionation Column Unit	125 gas/vapor valves	2014 - 2015
			125 light liquid valves	
			3 light liquid pumps	
			524 flanges	
			1 compressor seal	
			8 gas relief valves	

a. The above process units are subject to NSPS Subpart GGGa and shall comply with all applicable requirements for leak detection and repair. [40 CFR § 60.592(a)]

b. The owner operator shall comply with the requirements of §§ 60.482-1a through § 60.482-11a except as provided in § 60.593a:

1. The operator shall demonstrate compliance with §§ 60.482-1a to 60.482-10a for all affected equipment within 180 days of initial startup which shall be determined by review of records, reports, performance test results, and inspection using methods and procedures specified in § 60.485a unless the equipment is in vacuum service and is identified as required by § 60.486a(e)(5). [§ 60.482-1a(a), (b), & (d)]
2. The owner or operator shall comply with the monitoring, inspection, and repair requirements, for pumps in light liquid service, of §§ 60.482-2a(a), (b), and (c) except as provided in §§ 60.482-2a(d), (e), and (f).
3. Compressors in hydrogen service are exempt from the requirements of § 60.592a if an owner or operator demonstrates that a compressor is in hydrogen service. [§ 60.593a(b)(1)]
4. The owner or operator shall comply with the operation and monitoring requirements, for pressure relief devices in gas/vapor service, of §§ 60.482-4a(a) and (b) except as provided in § 60.482-4a(c) and (d).
5. The owner or operator shall comply with the applicable standards of § 60.482-5a for sampling connection systems.

1. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed. When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall be closed at all other times. [§ 60.482-6a]
2. The owner operator shall comply with the monitoring, inspection, and repair requirements, for valves in gas/vapor service and light liquid service, of §§ 60.482-7a(b) through (e), except as provided in 60.482-7a(f), (g), and (h), §§ 60.483-1a, 60.483-2a, and 60.482-1a(c). [§ 60.482-7a(a)]
3. The owner operator shall comply with the monitoring and repair requirements, or pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors, of §§ 60.482-8a(a) through (d). [§ 60.482-8a]

4. Delay of repair of equipment is allowed if it meets one of the requirements of §§60.482-9a(a) through (e).
5. The owner or operator using a closed vent system and control device to comply with these provisions shall comply with the design, operation, monitoring and other requirements of 60.482-10a(b) through (m). [§ 60.482-10a(a)]
6. The owner or operator shall comply with the applicable standards of § 60.482-11a for connectors in gas/vapor service and in light liquid service.
7. An owner or operator may elect to comply with the alternative requirements for valves of §§ 60.483-1a and 60.483-2a. [§ 60.592a(b) & § 60.482-1a(b)]
8. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the test method and procedures of § 60.485a except as provided in §§ 60.593a. [§ 60.592a(d)]
9. Each owner or operator subject to the provisions of NSPS Subpart GGGa shall comply with the recordkeeping requirements of § 60.486a and the reporting requirements of § 60.487a. [§ 60.592a(e)]

EUG-33 Modified CDU Heater

Point ID	Emission Unit	PM_{10}		SO_2		NOx		VOC		CO	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
6155	CDU Atmospheric Tower Heater	2.85	12.48	10.02	16.31	15.20	66.58	2.05	8.98	19.0	57.9

a. The above combustion unit shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR Part 60, Subpart Ja]

1. §60.100a Applicability, designation of affected facility, and reconstruction.
2. §60.101a Definitions.
3. §60.102a Emissions limitations.
4. §60.103a Design, equipment, work practice or operational standards.
5. §60.104a Performance tests.
6. §60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).
7. §60.106a Monitoring of emissions and operations for sulfur recovery plants.
8. §60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.
9. §60.108a Recordkeeping and reporting requirements.
10. §60.109a Delegation of authority.

b. The unit shall be fueled with refinery fuel gas or pipeline-grade natural gas only.

[OAC 252:100-8-6(a)(1) and OAC 252:100-31]

c. NOx emissions from the above heater shall not exceed 0.04 lb/MMBTU, expressed as NO_2 (3-hour average). CO emissions shall not exceed 0.05 lb/MMBTU (3-hour average). CO_2e emissions shall not exceed 146 lb/MMBTU (3-hour average). PM emissions shall not exceed 0.0076 lb/MMBTU (3-hour average). [OAC 252:100-8-6(a)(1)]

d. Performance testing as required by 40 CFR Part § 60.8 shall be conducted within 60 days of achieving maximum production rate, not to exceed 180 days from initial start-up following modifications. [40 CFR § 60.8]

e. The emissions of particulate matter resulting from the combustion of fuel in any new or existing fuel-burning unit shall not exceed the limits specified in OAC 252:100 Appendix C.

[OAC 252:100-19-4]

f. All fuel-burning equipment shall be operated and maintained to minimize emissions of VOC. Such conditions mean adherence to manufacturer's recommendations or to good operating and maintenance practices, and that temperature and sufficient air to provide essentially complete combustion are supplied. [OAC 252:100-37-36]

EUG 34 Stationary SI Engines Subject to 40 CFR Part 63 Subpart ZZZZ

ID Number	HP	Description	Construction/ Modification Date
007-J-26G	75	Kohler 50RZB 4SRB emergency engine	2004
008-PA-50	75	Kohler 50RZGB-051 4SRB emergency engine	2003
050-G-1M	66	Kohler 20RZ-Q5 4SRB emergency engine	2002
004-G-1	104	Kohler 304Z-QS 4SRB emergency engine	2001
012-G-1M	421	Kohler 275RZD 4SRB emergency engine	2004

a. The owner/operator shall comply with all applicable requirements of the NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE), Subpart ZZZZ, for the above emergency engines, including but not limited to: [40 CFR §§ 63.6580 to 63.6675]

1. § 63.6580 What is the purpose of subpart ZZZZ?
2. § 63.6585 Am I subject to this subpart?
3. § 63.6590 What parts of my plant does this subpart cover?
4. § 63.6595 When do I have to comply with this subpart?
5. § 63.6600 What emission limitations and operating limitations must I meet?
6. § 63.6605 What are my general requirements for complying with this subpart?
7. § 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations?
8. § 63.6615 When must I conduct subsequent performance tests?
9. § 63.6620 What performance tests and other procedures must I use?
10. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
11. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?
12. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

13. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?
14. § 63.6645 What notifications must I submit and when?
15. § 63.6650 What reports must I submit and when?
16. § 63.6655 What records must I keep?
17. § 63.6660 In what form and how long must I keep my records?
18. § 63.6665 What parts of the General Provisions apply to me?
19. § 63.6670 Who implements and enforces this subpart?
20. § 63.6675 What definitions apply to this subpart?

EUG 34a Stationary Engines Subject to 40 CFR Part 60 Subpart JJJJ

ID Number	HP	Description	Construction/ Modification Date
045-G-1M	360	Kohler 275 RZDB 4SRB emergency engine	2010
006-PE-80M	45	Kohler 25RZGB 4SRB emergency engine	2008

a. The above engines are subject to 40 CFR Part 60, Subpart JJJJ, and shall comply with all applicable standards for owners or operators of stationary spark ignition internal combustion engines: [40 CFR §§ 60.4230 to 60.4248]

1. § 60.4230: Am I subject to this subpart?
2. § 60.4231: What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines?
3. § 60.4232: How long must my engines meet the emissions standards if I am a manufacturer of stationary SI internal combustion engines?
4. § 60.4233: What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?
5. § 60.4234: How long must I meet the emissions standards if I am an owner or operator of a stationary SI internal combustion engine?
6. § 60.4235: What fuel requirements must I meet if I am an owner or operator of a stationary SI internal combustion engine?
7. § 60.4236: What is the deadline for importing or installing stationary SI ICE produced in the previous model year?
8. § 60.4237: What are the monitoring requirements if I am an owner or operator of a stationary SI internal combustion engine?
9. § 60.4238: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\leq$ 19 KW (25 HP).
10. § 60.4239: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\geq$ 19 KW (25 HP) that use gasoline?
11. § 60.4240: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\geq$ 19 KW (25 HP) that use LPG?
12. §60.4241: What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program?
13. §60.4242: What other requirement must I meet if I am a manufacturer of stationary SI internal combustion engines?

14. § 60.4243: What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?
15. § 60.4244: What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?
16. §60.4245: What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?
17. § 60.4246: What parts of the General Provisions apply to me?
18. § 60.4247: What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines?
19. § 60.4248: What definitions apply to this subpart?

<u>EUG 35 Stationary CI Engines Subject to 40 CFR Part 63 Subpart ZZZZ</u>

ID Number	HP	Description	Construction/ Modification Date
009-PE-143	700	Cummins VT-1710-F CI emergency engine	1977
009-PE-144	262	John Deere 6081HF001 CI emergency engine	Pre-2002

a. The owner/operator shall comply with all applicable requirements of the NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE), Subpart ZZZZ, for the above emergency engines, including but not limited to: [40 CFR §§63.6580 to 63.6675]

1. § 63.6580 What is the purpose of subpart ZZZZ?
2. § 63.6585 Am I subject to this subpart?
3. § 63.6590 What parts of my plant does this subpart cover?
4. § 63.6595 When do I have to comply with this subpart?
5. § 63.6600 What emission limitations and operating limitations must I meet?
6. § 63.6605 What are my general requirements for complying with this subpart?
7. § 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations?
8. § 63.6615 When must I conduct subsequent performance tests?
9. § 63.6620 What performance tests and other procedures must I use?
10. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?
11. § 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?
12. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?
13. § 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?
14. § 63.6645 What notifications must I submit and when?
15. § 63.6650 What reports must I submit and when?
16. § 63.6655 What records must I keep?
17. § 63.6660 In what form and how long must I keep my records?
18. § 63.6665 What parts of the General Provisions apply to me?
19. § 63.6670 Who implements and enforces this subpart?
20. § 63.6675 What definitions apply to this subpart?

EUG 35a Stationary Engines Subject to 40 CFR Part 60 Subpart IIII

ID Number	HP	Description	Construction/ Modification Date
033-EG-5320	700	Caterpillar C18 214-0021 CI emergency engine	2010
009-PE-152	380	Cummins CFP15E-F10 CI emergency engine	2014

b. The above engines are subject to 40 CFR Part 60, Subpart IIII, and shall comply with all applicable requirements: [40 CFR § § 60.4200 – 4219]

1. §60.4200: Am I subject to this subpart?
2. §60.4201: What emissions standards must I meet for non-emergency engines if I am a stationary CI engine manufacturer?
3. §60.4202: What emissions standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacture?
4. §60.4203: How long must my engines meet the emissions standards if I am a stationary CI internal combustion engine manufacturer?
5. §60.4204: What emissions standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
6. §60.4205: What emissions standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
7. §60.4206: How long must my engines meet the emissions standards if I am a owner or operator of a stationary CI internal combustion engine?
8. §60.4207: What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?
9. §60.4208: What is the deadline for importing or installing stationary CI ICE produced in the previous model year?
10. §60.4209: What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?
11. §60.4210: What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?
12. §60.4211: What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?
13. §60.4212: What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?
14. §60.4213: What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?
15. §60.4214: What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?
16. §60.4215: What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?
17. §60.4216: What requirements must I meet for engines used in Alaska?

18. §60.4217: What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?
19. §60.4218: What parts of the General Provisions apply to me?

Insignificant Activities

Various records shall be maintained to demonstrate the continued status of certain emission sources as Insignificant Activities, as follow. [OAC 252:100-43]

1. The amount of fuel dispensed from tanks #419 and #420 (monthly).

2. Vapor pressure for any tanks satisfying the criteria of capacity less than 39,894 gallons and storing a liquid with vapor pressure less than 1.5 psia (annual maximum).

3. Number of drums no larger than 55 gallons and containing less than 3% by volume of residual material, washed and/or crushed (annual).

4. Total emissions from any source classified as Insignificant on the basis of its emissions (annual), as well as a description of the calculation method used and data used in the calculation.

EUG Plant-Wide Miscellaneous

a. Certain equipment within the refinery is subject to 40 CFR Part 63 Subpart CC and all affected equipment shall comply with all applicable requirements. Requirements listed in previous EUGs are not repeated here. [40 CFR Part 63 Subpart CC]

   1. § 63. 63.642 General Standards
   2. § 63.643 Miscellaneous Process Vent Provisions
   3. § 63.644 Monitoring for Miscellaneous Process Vents
   4. § 63.645 Test Methods and Procedures for Miscellaneous Process Vents
   5. § 63.654 Reporting and Recordkeeping Requirements
   6. The permittee shall comply with the provisions of 40 CFR Part 63 Subpart A as specified in Appendix to Subpart CC, Table 6.

b. Various asbestos renovation and demolition projects at the Tulsa Refinery are subject to State and Federal standards, including:

   1. The federal standards found in 40 CFR Part 61 Subpart M. [40 CFR § 61.145]
   2. The following requirements for handling asbestos are in addition to those listed in the asbestos NESHAP, 40 CFR Part 61 Subpart M. [OAC 252:100-40-5]

A. Before being handled, stored or transported in or to the outside air, friable asbestos from demolition/renovation operations shall be double bagged in six-mil plastic bags, or single bagged in one six-mil plastic bag and placed in a disposable drum, or contained in any other manner approved in advance by the AQD Director.
B. When demolition/renovation operations must take place in the outdoor air, friable asbestos removed in such operations shall be immediately bagged or contained in accordance with (A).
C. Friable asbestos materials used on pipes or other outdoor structures shall not be allowed to weather or deteriorate and become exposed to, or dispersed in the outside air.
D. Friable asbestos materials shall, in addition to other provisions concerning disposal, be disposed of in a facility approved for asbestos by the Solid Waste Management Division of DEQ.

c. The following procedures are required for any process unit shutdown, purging, or blowdown operation. [OAC 252:100-39-16]

1. Recovery of VOC shall be accomplished during the shutdown or turnaround to a process unit pressure compatible with the flare or vapor system pressure. The unit shall then be purged or flushed to a flare or vapor recovery system using a suitable material such as steam, water or nitrogen. The unit shall not be vented to the atmosphere until pressure is reduced to less than 5 psig through control devices.
2. Except where inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline," or any State of Oklahoma regulatory agency, no person shall emit VOC gases to the atmosphere from a vapor recovery blowdown system unless these gases are burned by smokeless flares or an equally effective control device as approved by the Division Director.
3. At least fifteen days prior to a scheduled turnaround, a written notification shall be submitted to the Division Director. As a minimum, the notification shall indicate the unit to be shutdown, the date of shutdown, and the approximate quantity of VOC to be emitted to the atmosphere.
4. Scheduled refinery unit turnaround may be accomplished without the controls specified in (a) and (b) during non-oxidant seasons provided the notification to the Division Director as required in (c) specifically contains a request for such an exemption. The non-oxidant season is from November 1 through March 31.

d. Non-condensable VOC from surface condensers and accumulators in the CDU vacuum producing system shall be vented to a heater firebox. [OAC 252:100-39-17]

e. Cold metal-cleaning units using any VOC shall comply with the following requirements.

1. Mechanical design. The unit shall have a cover or door that can be easily operated with one hand, and shall have an internal drain board allowing lid closure or an external drain facility if the internal option is not practical. The unit shall have a permanently attached conspicuous label summarizing the operating requirements. [OAC 252:100-39-42(a)(1)]

2. Operating requirements. All clean parts shall drain for at least 15 seconds or until dripping ceases before removal, the degreaser cover shall be closed when not handling parts, and VOC shall be sprayed only in a solid fluid stream, not in an atomized spray. Waste VOC shall be stored in covered containers and waste VOC shall not be handled in such a manner that more than 20% by weight can evaporate. [OAC 252:100-39-42(a)(2)]
3. If the VOC used has vapor pressure greater than 0.6 psia or if the VOC is heated to 248 °F, the unit requires additional control. Such control shall be a freeboard with ratio at least 0.7, a water cover where the VOC is insoluble in and denser than water, or another system of equivalent control as approved by the AQD Director. [OAC 252:100-39-42(a)(3)]

f. A startup, shutdown, and malfunction plan has been prepared in compliance with 40 CFR Part 63 Subpart A. The current plan shall be retained for the life of the facility and superseded versions of the plan shall be retained for five years after the date of revision. Both current and retained versions shall be readily available for review.[40 CFR § 63.6(e)(3)]

g. VOC storage vessels greater than 40,000 gallons in capacity and storing a liquid with vapor pressure greater than 1.5 psia shall be pressure vessels or shall be equipped with one of several vapor loss control systems. [OAC 252:100-37-15(a)]

h. Activities at EUG 18 have established that HFTR is subject to 40 CFR Part 63 Subpart GGGGG. Any and all other activities at HFTR that are "site remediations" as defined in §63.7957 and satisfy the requirements of §63.7881(a), unless otherwise exempted, shall comply with any applicable requirements, including, but not limited to: §§63.7880 - 7883 What This Subpart Covers.

1. § 63.7884 - 7888 General Standards
2. § 63.7890 - 7893 Process Vents
3. § 63.7895 - 7898 Tanks
4. § 63.7900 - 7903 Containers
5. § 63.7920 - 7922 Equipment Leaks
6. § 63.7935 - 7938 General Compliance Requirements
7. § 63.7950 - 7953 Notifications, Reports, and Recordkeeping
8. § 63.7955 - 7957 Other Requirements and Information
9. The permittee shall comply with the provisions of 40 CFR Part 63 Subpart A as specified in Appendix to Subpart GGGGG, Table 3.

SPECIFIC CONDITION 3

a. No later than 30 days after each anniversary date of the issuance of the initial Title V permit (September 1, 2002), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, certification of compliance with the terms and conditions of this permit. [OAC 252:100-8-6 (c)(5)(A) & (D)]

b. Alternatively, the facility may submit an additional compliance report covering the period of September 1 to December 31, and thereafter submit certifications of compliance for the period of January 1 to December 31. All reports are due 30 days following the period which is covered by the report.

SPECIFIC CONDITION 4

Construction Permit No. 2007-005-C (M-1) and Construction Permit No. 2007-005-C (M-14) will remain in effect. Upon issuance, this permit replaces and supersedes Permit No. 2012-1062-C (M-1)(PSD), (M-6)(PSD), and (M-8)(PSD).

SPECIFIC CONDITION 5

The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility. [OAC 252:100-8-6(d)(2)]

OAC 252:100-7	Minor Sources	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-47	Municipal Solid Waste Landfills	not in source category

SPECIFIC CONDITION 6

Within 180 days following commencement of operations of each new or modified heater authorized by this permit, performance testing shall be conducted and a written report of results submitted to AQD documenting compliance with emissions limitations by each new or modified heater. The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality: [OAC 252:100-43]

Method 1: Sample and Velocity Traverses for Stationary Sources
Method 2: Determination of Stack Gas Velocity and Volumetric Flow Rate
Method 3: Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight
Method 4: Moisture in Stack Gases.
Method 5: Filterable PM Emissions from Stationary Sources
Method 6C: SO_2 Emissions from Stationary Sources
Method 7E: NOx Emissions from Stationary Sources
Method 10: Carbon Monoxide Emissions from Stationary Sources
Method 25A: VOC Emissions from Stationary Sources
Method 202: Condensable PM Emissions from Stationary Sources

A copy of the test plan shall be provided to AQD at least 30 days prior to each test date.

Performance testing shall be conducted while the heater is operating within 10% of the rate at which operating permit authorization will be sought.

At least 30 days prior to the testing, a notification of the test date and testing protocol shall be submitted to AQD. Deficiencies in the protocol shall be resolved prior to commencement of testing.

SPECIFIC CONDITION 7

New tanks will be added to the East Refinery, but the final designs are not yet ready. As an interim measure, a limit of 1.20 TPY VOC (which includes roof landing emissions, if any) from the new tanks will be established.

SPECIFIC CONDITION 8

The permittee shall apply for a modified operating permit within 180 days of start-up of any new unit authorized under this construction permit.

SPECIFIC CONDITION 9

The permittee shall keep records of actual emissions and comparisons to Baseline Actual Emissions for as required by OAC 252:100-8-36.2(c). These records shall be made available upon request.

SPECIFIC CONDITION 10

As part of the operating permit application, the permittee shall submit maximum anticipated throughputs and resultant VOC emissions for the organic liquids storage tanks in EUG-3 and EUG-20. [OAC 252:100-8-6]

SPECIFIC CONDITION 11

Concurrent with installation and operation of new and modified units associated with the Refinery Expansion that will increase VOC emissions, HFTR shall complete physical changes to the East Refinery wastewater system to reduce VOC emissions by 40 TPY. Uncovered drain vents to atmosphere shall be covered with P-trap type water seals or other type seals. The facility shall maintain a list of drains controlled and the dates of installation of controls of each drain which is controlled.

SPECIFIC CONDITION 12

This permit supersedes and cancels Permit No. 2012-1062-C (M-13)(PSD).

Jennifer Sanchez, Environmental Manager
HollyFrontier Tulsa Refining LLC – Tulsa, LLC
1700 S. Union Avenue
Tulsa, OK 74107

Re: Part 70 Permit No. **2017-1908-C (M-2)(PSD)**
Tulsa Refinery East (FAC ID 1458)

Dear Ms. Sanchez:

Enclosed is the modified Part 70 construction permit authorizing modification of the referenced facility. Please note that this permit is issued subject to certain standard and specific conditions that are attached.

Also note that you are required to annually submit an emission inventory for this facility. An emission inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emission Inventory Staff at (405) 702-4100.

Thank you for your cooperation in this matter. If we may be of further service, please contact our office at (918) 293-1600. Air Quality personnel are located in the DEQ Regional Office at Tulsa, 9933 East 16th Street, Tulsa, OK, 74128.

Sincerely,

David S. Schutz, P.E.
New Source Permits Section
Air Quality Division

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2017-1908-C (M-2)(PSD)

HollyFrontier Tulsa Refining LLC – Tulsa, LLC,

having complied with the requirements of the law, is hereby granted permission to modify the Tulsa Refinery (East), 902 W. 25th Street, Tulsa, Tulsa County, Oklahoma, subject to standard conditions dated June 21, 2016, and specific conditions, both attached.

In the absence of commencement of construction, this permit shall expire 18 months from the date below, except as authorized under Section VIII of the Standard Conditions.

Division Director **Air Quality Division**	**Date**

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(June 21, 2016)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:
(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.
[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.

[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.
[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.
[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.
[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.
[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.

(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(17) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.
[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.
[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.

(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.

[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter.

[OAC 252:100-13]

(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and

(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.

(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).

(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).

(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).

(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA’s objections are resolved to the satisfaction of EPA.

(6) The DEQ complies with 40 C.F.R. § 70.8(d).

(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]